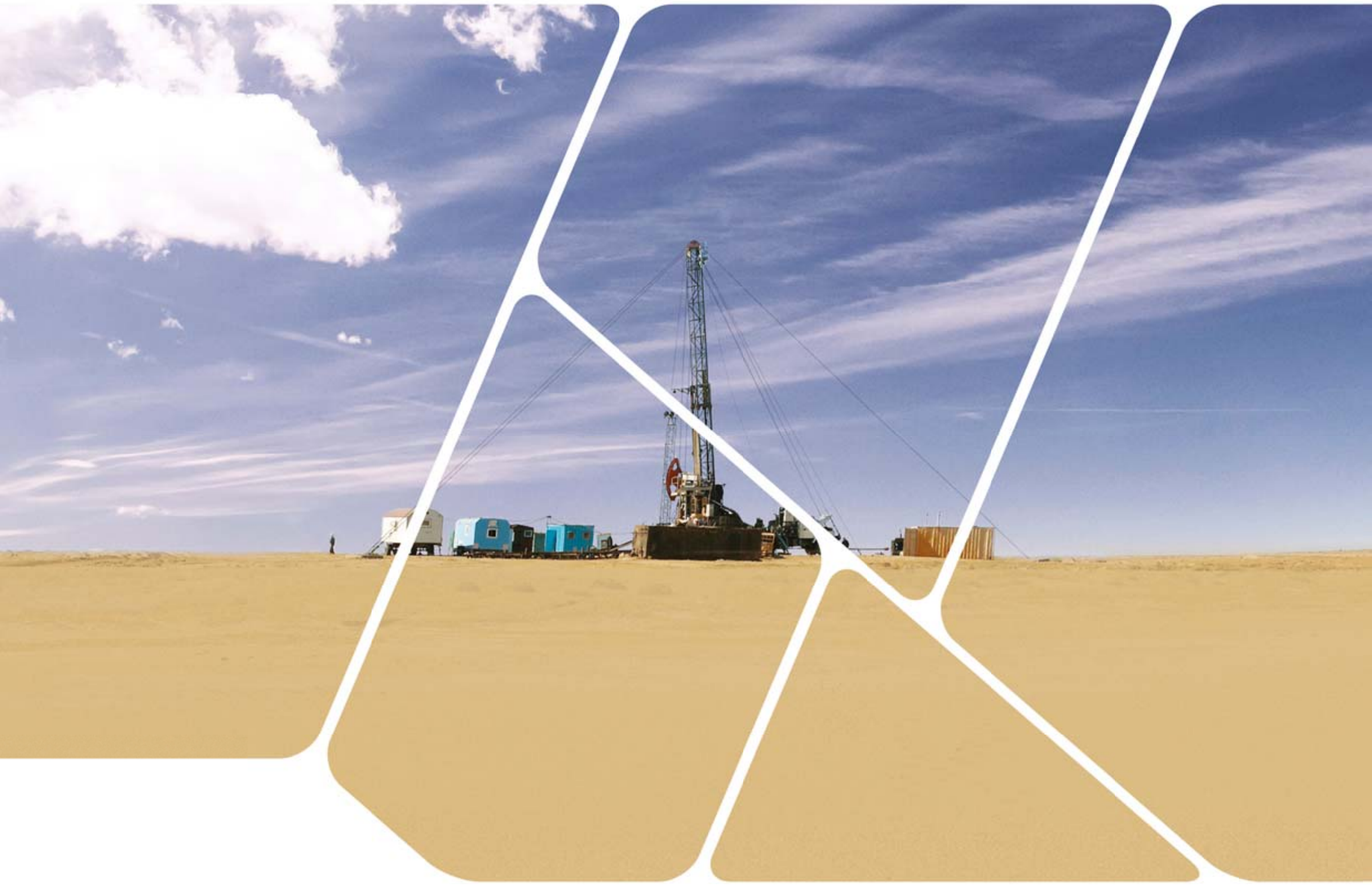


W2 : Petroleum Engineering

Formation certifiante en Management de la chaine de valeur de l'EP et Ingénierie pétrolière – *Du 13 Novembre au 17 Novembre 2016*

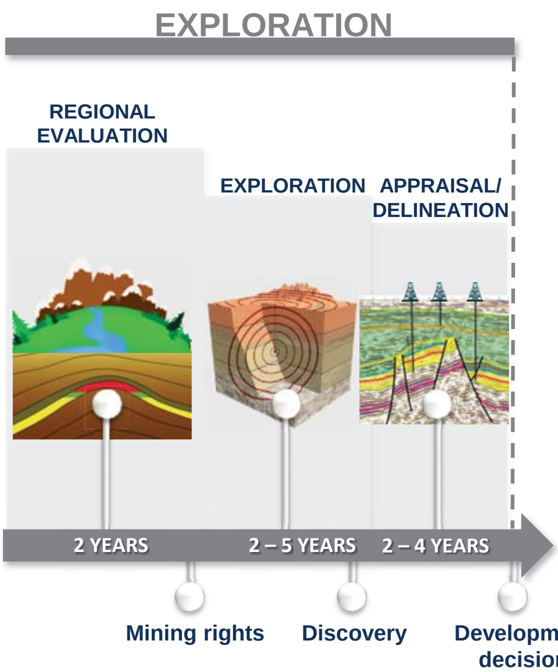
Introduction to Reservoir Engineering

Week#2

PTTEP Algeria

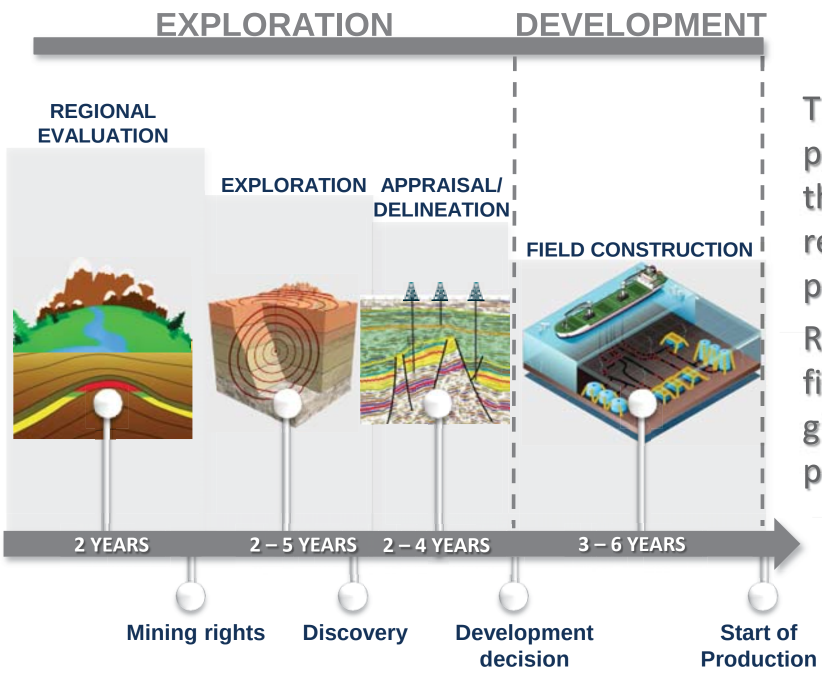
November 2016

Objectives of reservoir engineering



After the discovery of a reservoir, the goal of reservoir engineering is to set up a field development project that will attempt to optimize the recovery of hydrocarbons as part of an overall economic policy.

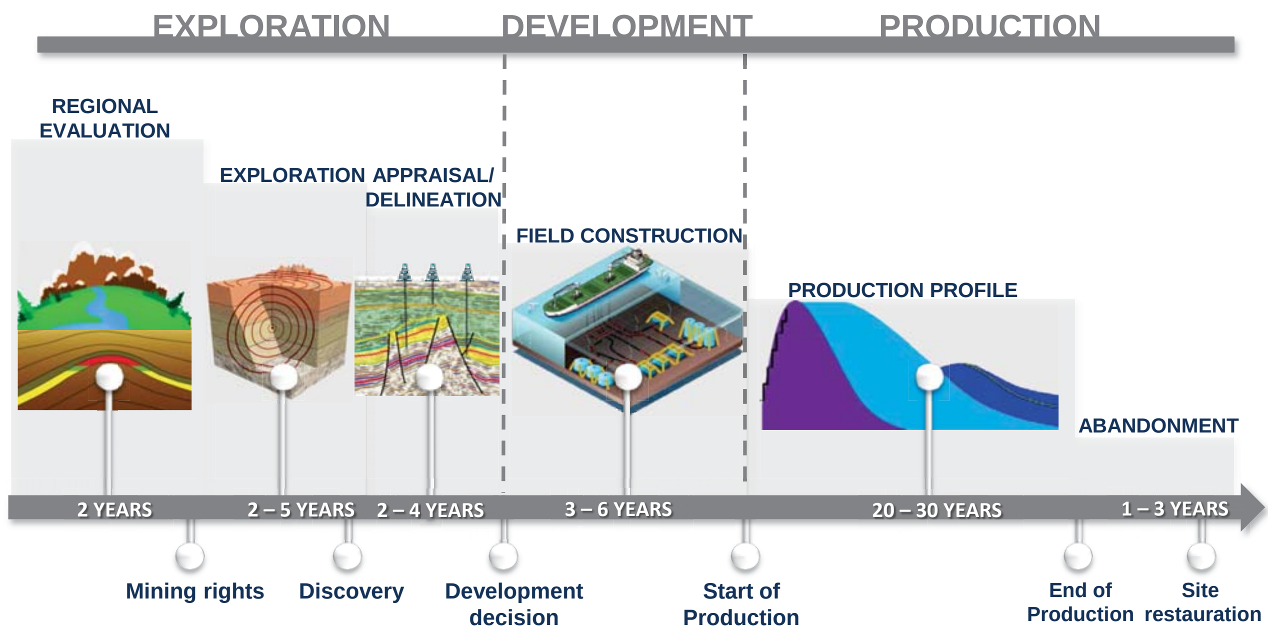
Objectives of reservoir engineering



The optimal profitability of a project needs the knowledge of the OHIP, the recoverable reserves and the wells productivity potentials.

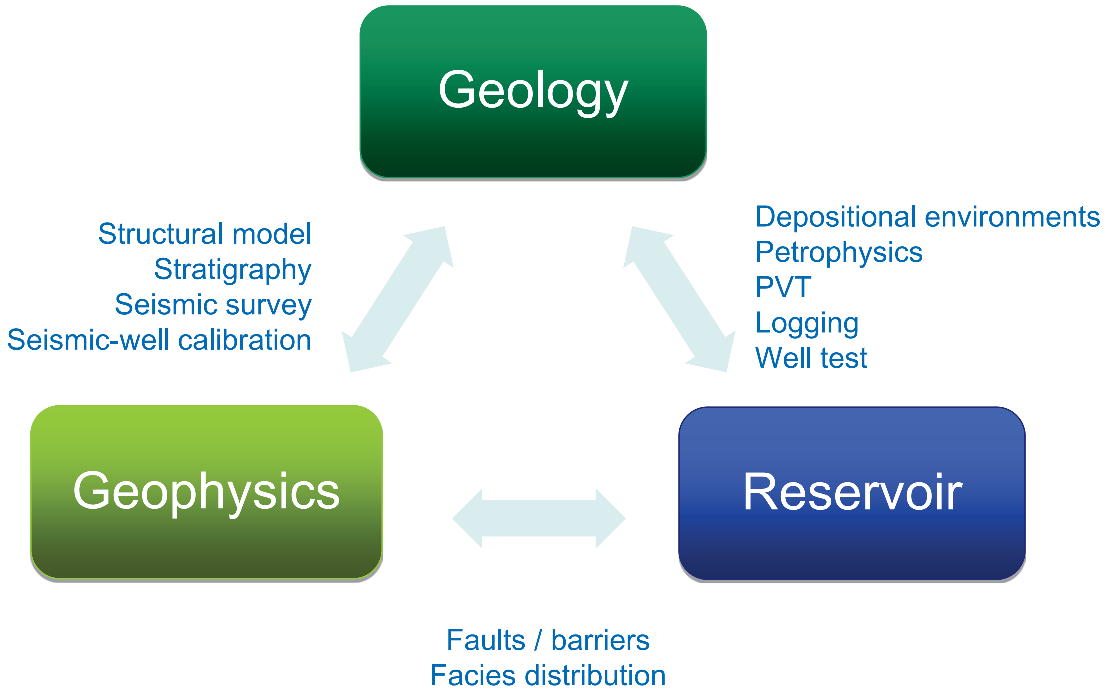
Reservoir engineering provides a field development strategy giving the input for drilling and production engineering.

Objectives of reservoir engineering

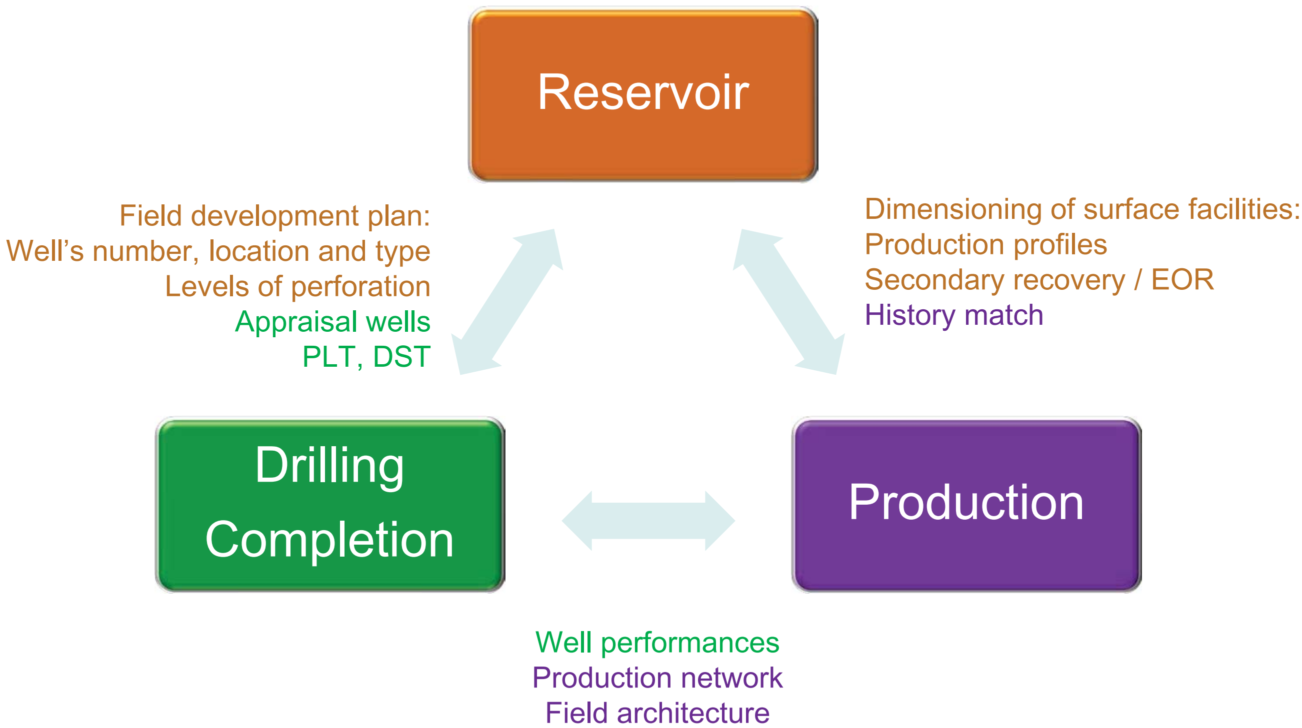


During the reservoir life, the Reservoir specialist will continue to study the behaviour of the reservoir throughout the life of the field to derive the information required for optimal production from the reservoir.

Multidisciplinary approach



Multidisciplinary approach



Course outline

- Fundamentals of reservoir characterization for modeling
- Fundamentals of reservoir engineering
- Field development: case study
- Fundamentals of reservoir simulation
- Reservoir simulation modeling: case study
- Reserves

Fundamentals of Reservoir Characterization for Modeling

Week#2

PTTEP Algeria

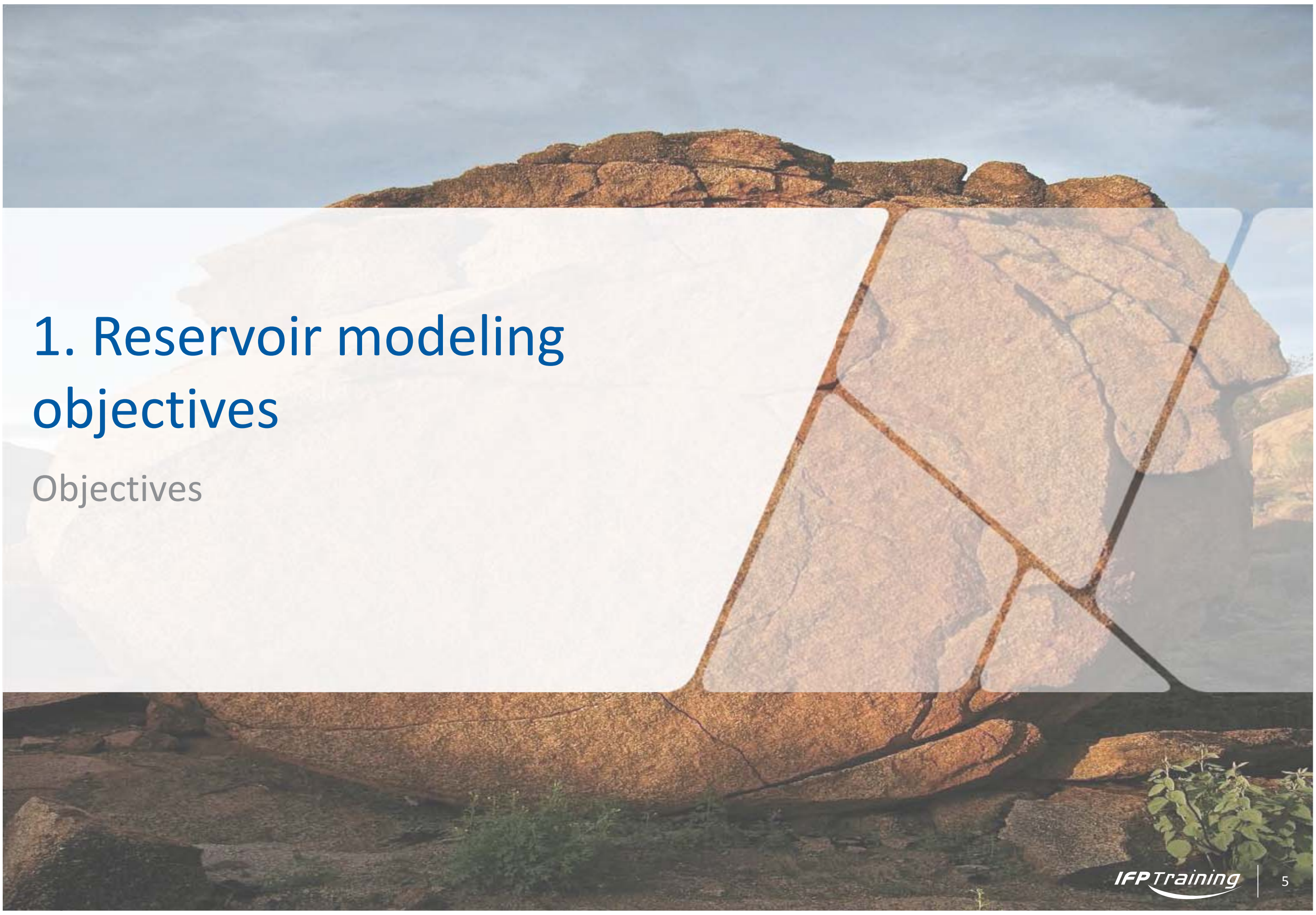
November 2016

Outline

1. **Reservoir modeling objectives**
2. **Static data integration & Geological modeling workflow**
3. **Geological modeling**
   - Part A: Static data integration
   - Part B: Geological modeling - Dynamic data integration
4. **Reservoir uncertainties**
5. **Reservoir heterogeneities**

Presentation summary

- **Reservoir modeling objectives**
  - Objectives of your company
  - Integrated Field Development Project: Objectives - Workflow
  - Reservoir characterization and modeling: Objectives
  - Work with your colleagues (Multidisciplinary team work)
- **Cellular models**
  - Examples:
    - Geological model
    - Field analog
  - Image parameters of a hydrocarbon field
  - Geocellular model definition
- **Geological model vs. Reservoir model**
  - Optimizing production (The key: the reservoir model)
  - Reservoir model definition (A reservoir model: what for?)
  - Specificity of reliable cellular models
  - Dynamic simulation to reduce reserves uncertainties



1. Reservoir modeling objectives

Objectives

Objectives of your company – 1/2

- **Main goal after a new discovery:**
  - Ensure field development project is economically profitable
  - → **Plan adequate field development to optimize recovery**
- **Throughout field life:**
  - Acquire relevant information to monitor reservoir behavior
  - → **Use recorded information to optimize production recovery**

→ **The proper way goes through reservoir modeling**

→ **The right man is the Reservoir Engineer**

Objectives of your company - 2/2

- **Optimal profitability of a project requires knowledge of:**
  - Volume of in-place hydrocarbons
  - Recoverable reserves (several scenarios)
  - Expected well performance (daily production)

➢ ***Porosity***

➢ ***Permeability***

➢ ***Heterogeneity***

→ **The proper way goes through geological modeling**

→ **The right man is the Reservoir Geologist**

Integrated field development project: Objectives

- **3D geological models: to help make relevant business decisions**
- **Flow simulation models: to predict reservoir performance**

→ **Production prediction: to plan capital expenditures, including:**
- Drilling new producers and injectors (infill design)
- Dimensioning & design of surface facilities (pipelines, crude & gas storage, water treatment,…)

→ **The right man is the Reservoir Engineer**

→ **A good reservoir model must integrate geological constrains**

Reservoir simulation objectives

- **End product of geological models = starting point for reservoir simulation**
- **Reservoir simulation = numerical simulation of both production and injection history of a field**
- **Models use (as input recorded data):**
  - Production and injection rates (from all field wells)
  - Pressure changes over time
  - Volumes of produced oil and water

Simulation → strong need for huge **computational power!**

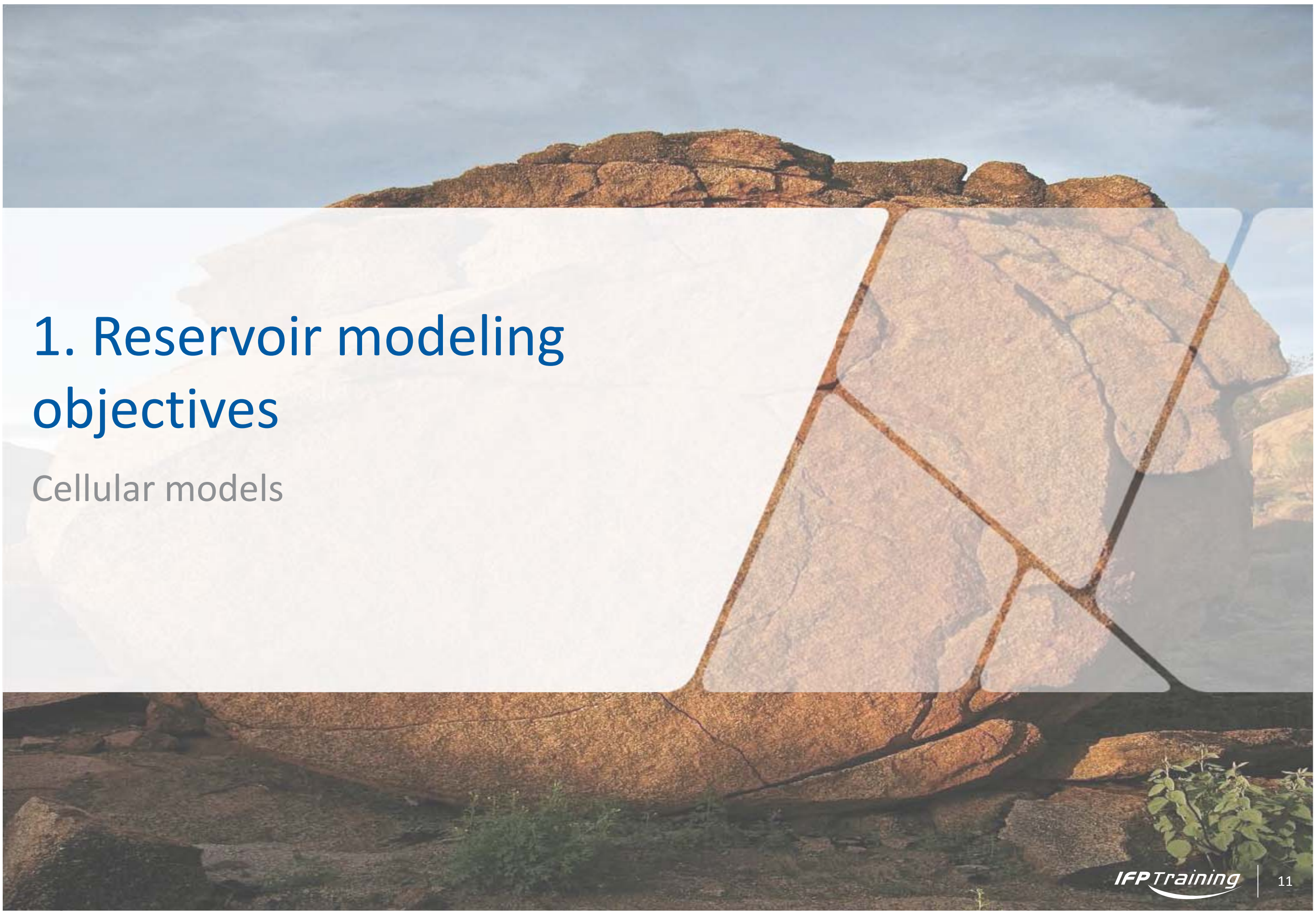
Work with your colleagues!

Multi-disciplinary team work

- **Geophysicist**
  - Seismic data interpretation (horizons, faults, seismic facies)
- **Log analyst**
  - Quantitative log interpretation (fluid contacts, petrophysical parameters)
- **Sedimentologist**
  - Core description, well correlations, sedimentological model
- **Lab petrophysicist**
  - Petrophysical measurements (on cores)
- **Geochemist**
  - Analysis of fluids, rocks, organic matter
- **Reservoir engineer**
  - Dynamic data synthesis, flow simulation, production prediction

The **reservoir geologist** must check data consistency during modeling.

→ He needs to **work with every actor** of an integrated study.



1. Reservoir modeling objectives

Cellular models

Example of a field analog outcrop

Monterralo anticline (Colombia)

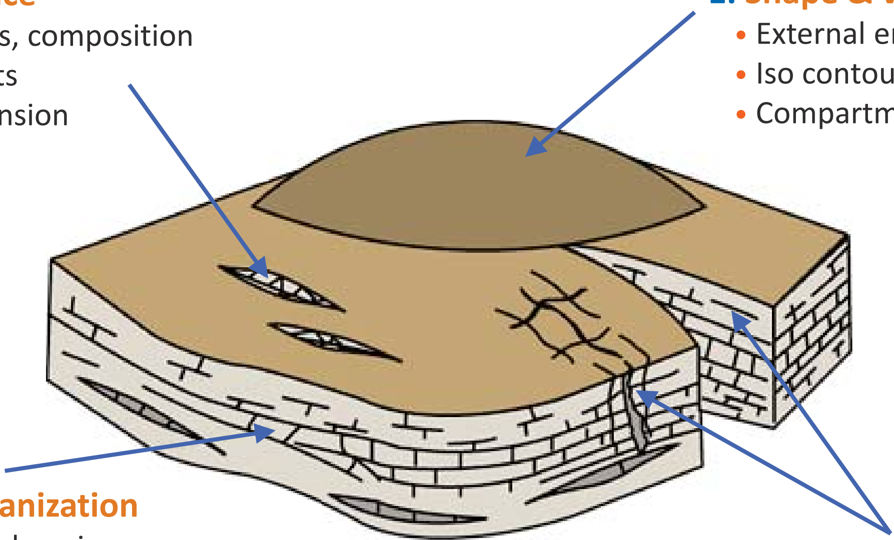
Nature is complex…

Image parameters of a hydrocarbon field

➔ Split a **complex problem** into several **simple ones**

4. Fluids in place
- Type of fluids, composition
- Fluid contacts
- Aquifer extension
- PVT, GOR

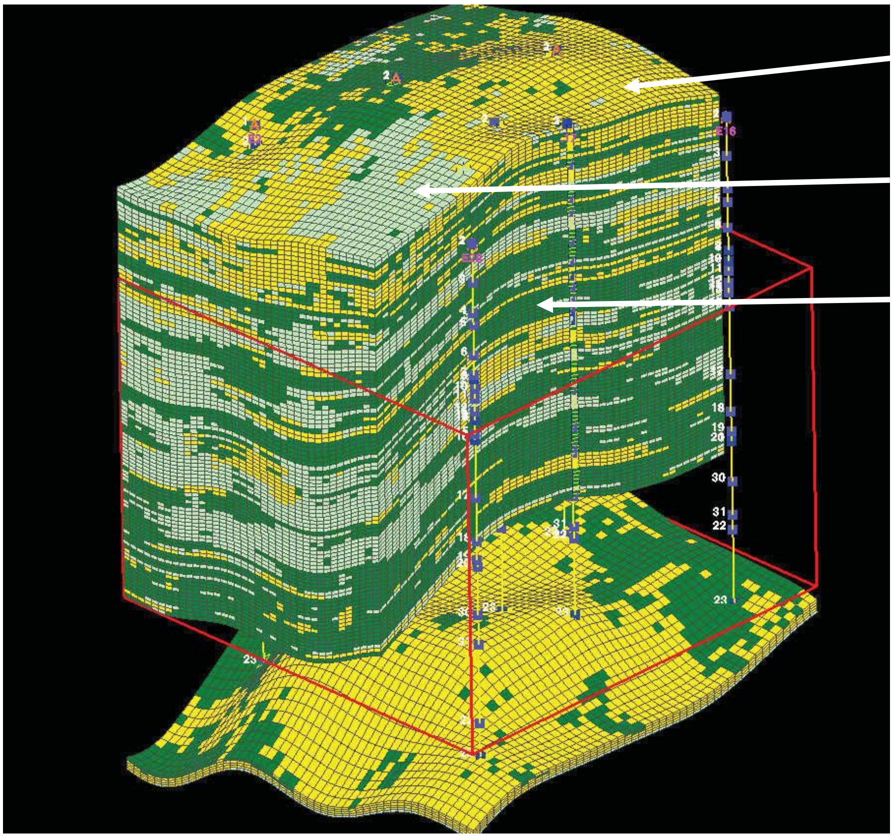
1. Shape & volume
- External envelope
- Iso contours (top-base)
- Compartments



3. Internal organization
- Correlations, layering
- Facies variation
- Petrophysics
- Drains, barriers (heterogeneities)

2. Structural framework
- Faults
- Fractured areas
- Micro fractures

Example of a geological model



Porous limestone

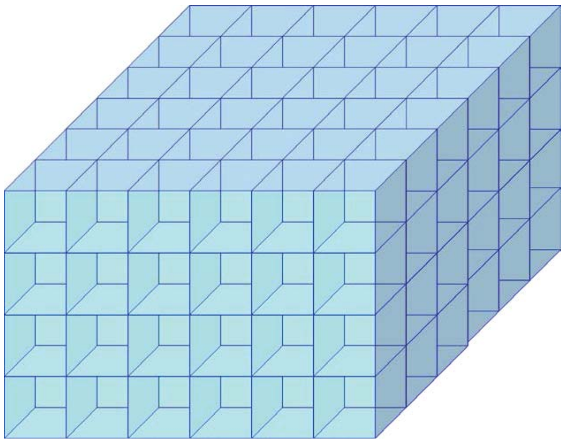
Tight limestone

Shaly limestone

Geological model in carbonates

Geocellular model definition

- **A cellular model is a schematic description of a reservoir that represents its properties**

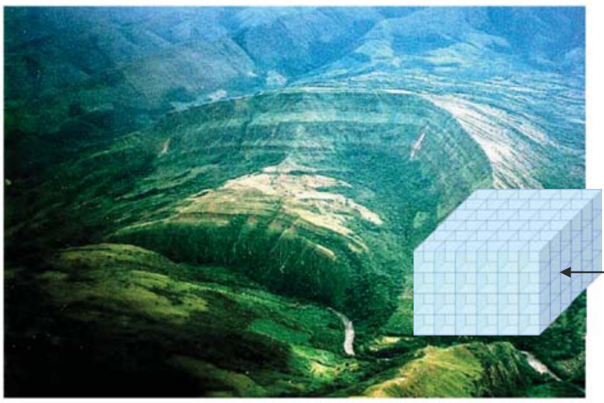


- **A cellular model is required:**
  - to understand the **complexity** of reality
  - to **quantify** reality
- **Modeling objectives: simplify to quantify**
- **Upscaling: amplify** (integrated, global vision)

1. Reservoir modeling objectives

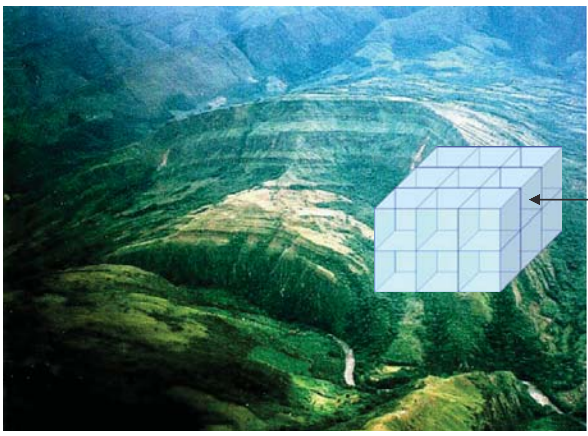
Geological model vs. Reservoir model

Geomodel vs Reservoir model – 1/2



Geological model (static)
for volume calculation

- **Net/Gross** thickness
- **Phi***e* (effective porosity)
- **K** (permeability)
- **S** (saturations: W, O, G)



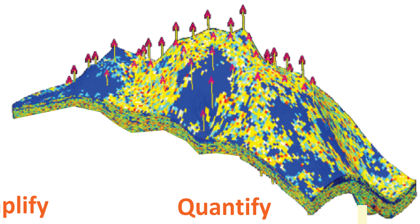
Reservoir model (dynamic)
for fluid flow simulation

Different objectives → Different cell size

Geomodel vs Reservoir model – 2/2

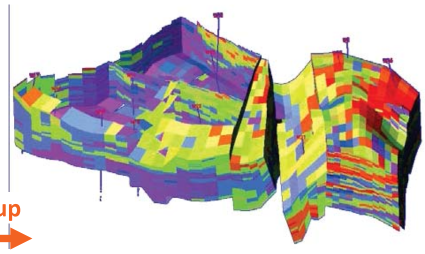
Reality	Geological model for static simulation	Reservoir model for dynamic simulation
	Characterize reservoir	Predict dynamic behavior

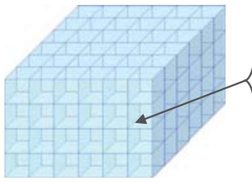
Simplify



Quantify

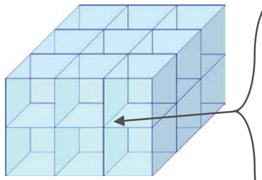
Scale up





- N/G
- Phi*e*
- K
- S

- Quantitative synthesis
- One model for each parameter:
  - To understand hydrocarbons spatial distribution
  - To calculate accumulations in place



- N/G
- Phi*e*
- K (Kx,Ky,Kz)
- S
- K*r*
- P*c*

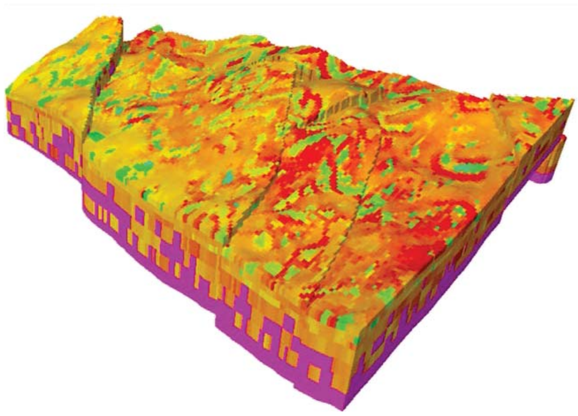
Not to **predict** the reservoir **content**

but to anticipate
its dynamic behavior

Upscaling: a challenge for information integration!

A reservoir model: what for?

- **A reservoir model is a grid of cells which allows manage and represent:**
  - Key heterogeneities (→ main flow units)
  - Lithofacies and petrophysical properties distribution consistency
- **A reservoir model is used to simulate the evolution of a field throughout time**



- **Monitor & analyze:**
  - Well production
  - Fluid movements within the reservoir
  - Pressure evolution

→ Anticipate
= Predict + Recommend actions

Specificities of reliable cellular model

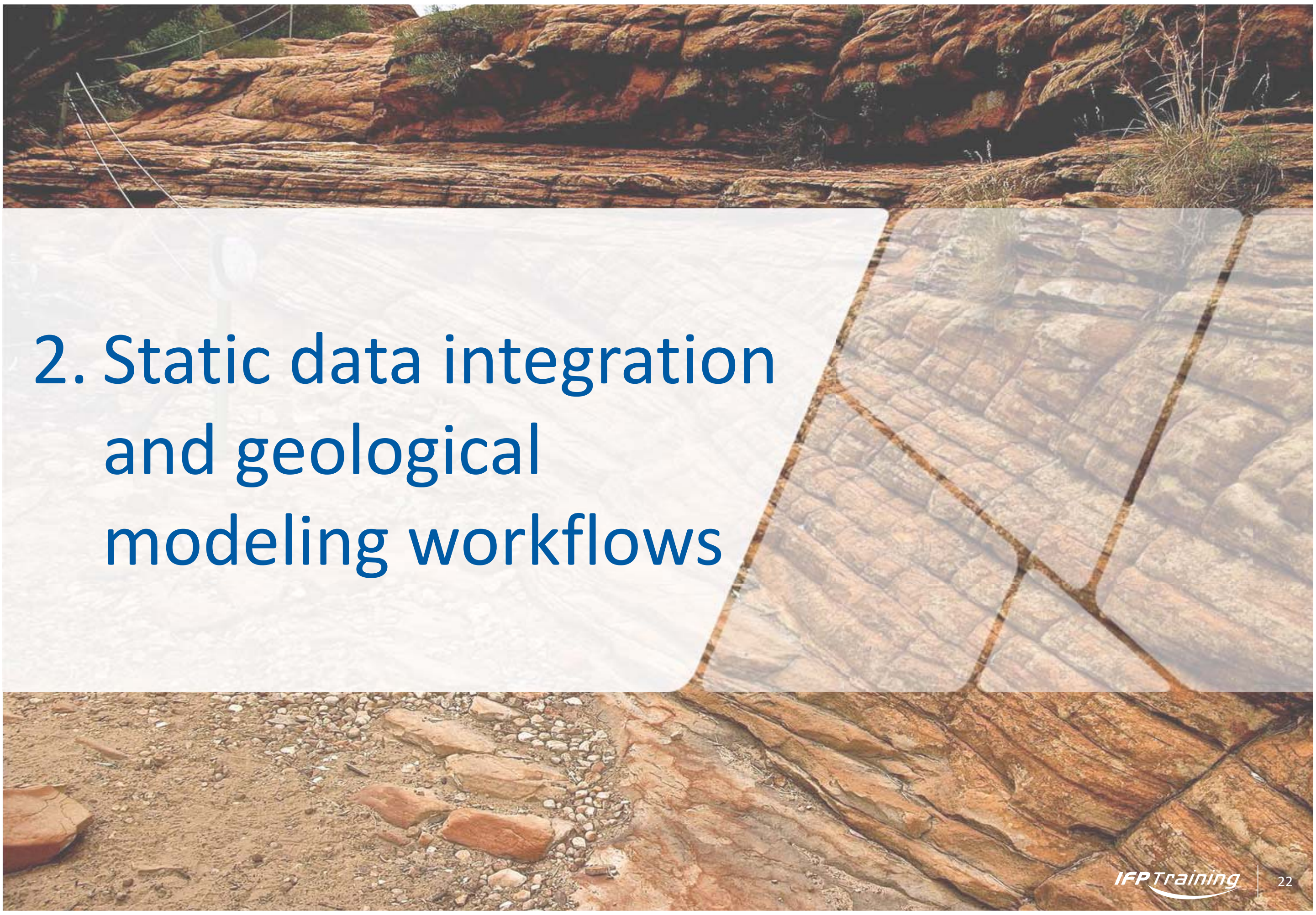
- **A good reservoir model is strongly constrained by the geological model:**
  - Fluid flow simulation is more realistic and more reliable
- **A reliable geological model takes into account dynamic data:**
  - Identification of main faults which impact fluid flow (either permeability barrier or conductive faults)
  - Stratigraphic barriers or multiple reservoirs

→ Need for strong integration between geo-disciplines (Geophysicists, Geologists, Reservoirs engineers) to ensure final model consistency (volume, pressure, rates)

Reservoir modeling objectives - Key points

- **Reservoir model* construction is the main objective of an integrated reservoir study.**
- **This model is used to simulate field evolution throughout time for:**
  - well production
  - fluid displacements (within the reservoir)
  - pressure evolution
- **The geomodel¤ represents one of the most important phases in an integrated reservoir study workflow, because:**
  - it integrates **reservoir geometry** and **petrophysical properties**
  - it takes into account **dynamic information**
  - it provides **key heterogeneity** for modeling

* Reservoir model = **Dynamic model**
¤ Geological model = Geomodel = Geocellular model = **Static model**



2. Static data integration and geological modeling workflows

Workflow summary

- **The key to success…**
- **Characterization workflow**
  - A consistent geological model
  - Structural
  - Stratigraphic
  - Lithological
- **Modeling workflow**
  - Geocellular model
  - Reservoir model
- **Reservoir heterogeneities**

The key to success: Two steps

- **Two main steps**

1. **Characterization**
   - Determine conceptual models for each discipline topic
   - Select relevant modeling parameters
   - Chose modeling sequence (according to available data)

1. **Modeling**
   - Use parameters resulting from characterization to build a numerical (digital, computerized) model

Notion of conceptual model

- **Conceptual models help integrated teams members reach a global understanding of studied reservoir**
- **Each preliminary model is related to parameters that will be used to populate the final numerical model**

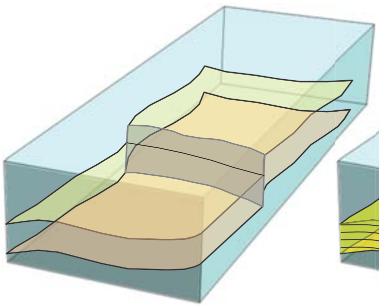
→ **Time for modeling will be reduced**

Notion of conceptual model

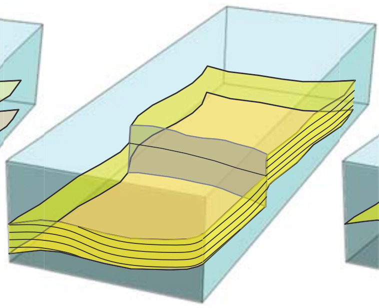
- **Make a conceptual model for each discipline topic, i.e.**
  - Structural
  - Stratigraphic
  - Sedimentological
  - Fracture
  - Diagenetical
  - Heterogeneity / Fluid flow
  - Dynamic fluid

→ **Prepare a table of uncertainties**

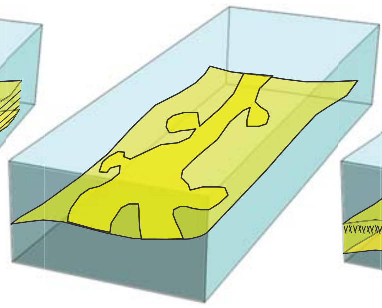
Conceptual models workflow



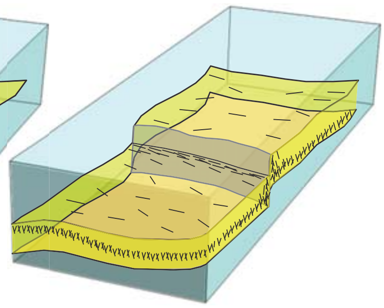
Structural model



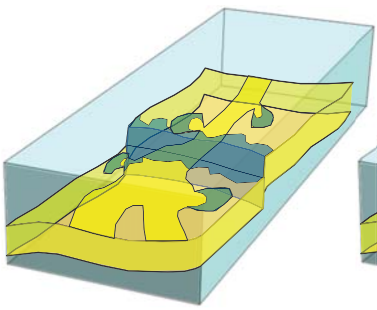
Stratigraphic model



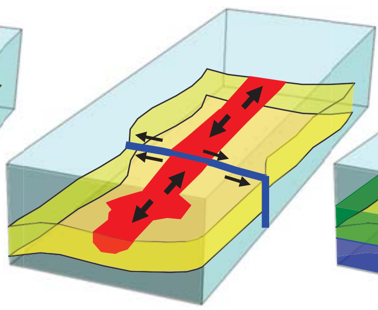
Sedimentological model



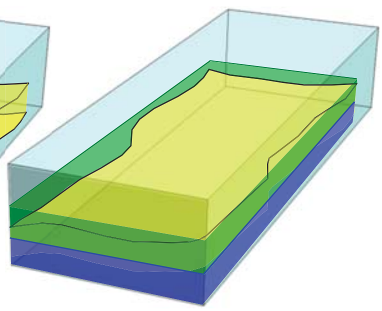
Fracture model



Diagenesis model



Heterogeneity model (fluid flow)



Fluid model

Uncertainties table

Rock Types	K	Φ	Pc
RT1	ΔK1	ΔΦ1	ΔPc1
RT2	ΔK2	ΔΦ2	ΔPc2
RT3	. . .	. . .	. . .

Available information summary: Table of uncertainties

- **Objectives**
  - Make a synthesis of uncertainty attached to each parameter
  - Determine parameters to integrate uncertainties (for OOIP calculation)
- **Based on**
  - Statistical distribution of each parameter

Reservoir characterization and modeling - Key points

- **An integrated reservoir study requires a multidisciplinary approach that integrates complementary techniques**
- **Prior to the modeling phase, characterization must be completed, and conceptual models should be built for each discipline/specialty/topic**
- **Modeling**
  - **Use conceptual models at each step of modeling process**
- **Describe each item with simple words**
  - e.g. faults:
    - Main faults are oriented N-S → Define dynamic compartments.
    - Secondary faults are oriented N45, without throw but with fault-related open fractures → Probable positive impact on dynamic behavior.

3. Geological modeling

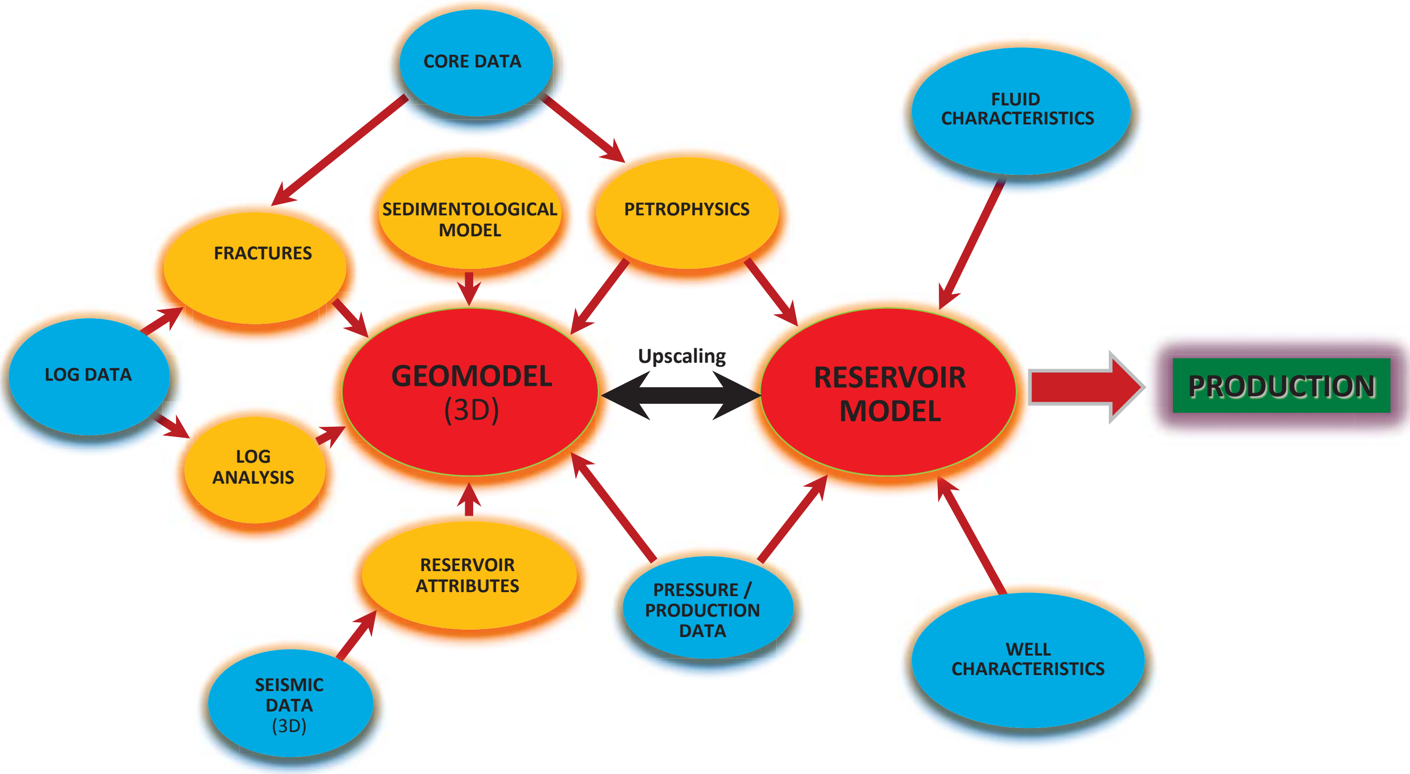
Part A: Static data integration

Presentation summary

- A multidisciplinary approach
- Database
- Data integration
- Data analysis
- Type of data
- Understanding the data
- Quality control

Database

What you need is …integration!



Everyone has the same objective: Produce!!!

Integration and database structure

- The project database is the main interface for the geoscientist
- A typical database contains 4 main types of data:

Types of data in a Project database

	Confidence	Audience	Life span	Example
Definitive (raw) data	High	Large	Forever	Well logs
Reference information	Moderate	Moderate	Moderate	Official maps
Project information	Low	Low	Short	Working maps
Personal files	-	Individual	Intermediate	Preference files

Integrated reservoir studies: Luca Cosentino

Type of data

Dynamic data

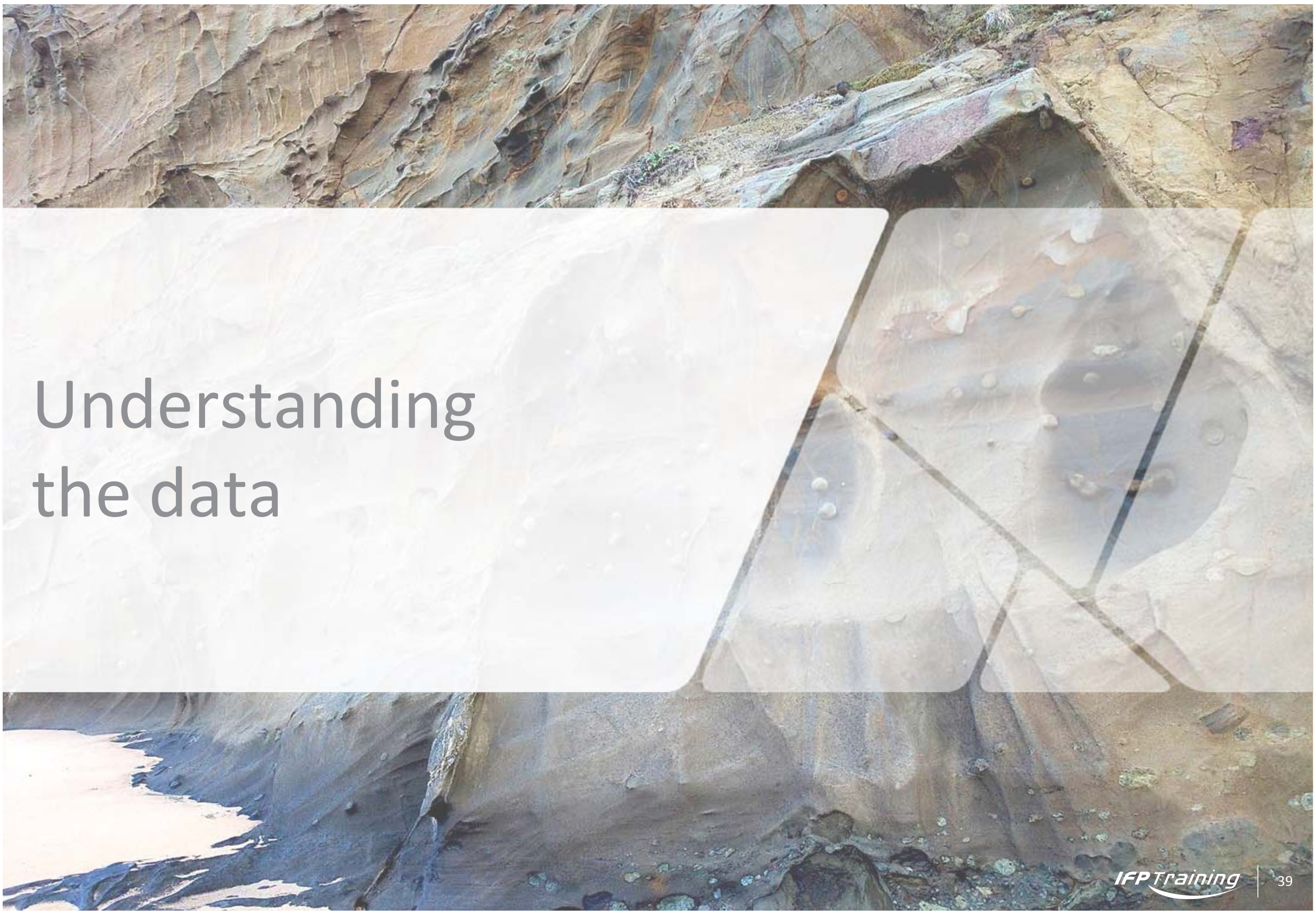
- **Well tests**
  - Evaluate [K.h]: average permeability of drained area around well
  - Estimate distance to flow borders (interference test)
- **Static pressure measurements**
  - Identify connected blocks
- **Production history**
  - Estimate OHIP with the Material Balance method
- **Capillary pressure curves for each facies**
  - Evaluate impact of Pc on permeability and recovery

Seismic data

- **Horizons**
  - From seismic picking (after time-to-depth conversion)
  - Good lateral definition but poor vertical accuracy
  - From 12.5 to 25 m in XY, ~ 3000 m/s * 4 ms = 12 m in depth
- **Faults**
  - From seismic picking (after time-to-depth conversion)
  - From 2D structural mapping
- **Seismic attribute maps (Net-to-Gross, average porosity, coherency…)**
  - Generate maps from seismic amplitudes, seismic attributes (both surface and volume) and calibrate them with well data
- **Seismic facies maps**

Well data

- **Well path in MD azimuth (converted to X, Y, Z)**
  - Accurate only in vertical wells or GPS measurements
- **Logs used for modeling**
  - **Porosity**: from NPHI-RHOB or SONIC logs and cores
  - **Permeability**: from PHI logs and cores
  - **Saturation**: from Resistivity logs and cores
  - **Facies**:
    - genetic (i.e. geology-oriented: lithofacies from cores)
    - rock types (i.e. petrophysics-oriented: petrofacies from SCAL)
- **Isochores/Isopachs**
  - From intermediate well markers
  - Generally smooth surfaces

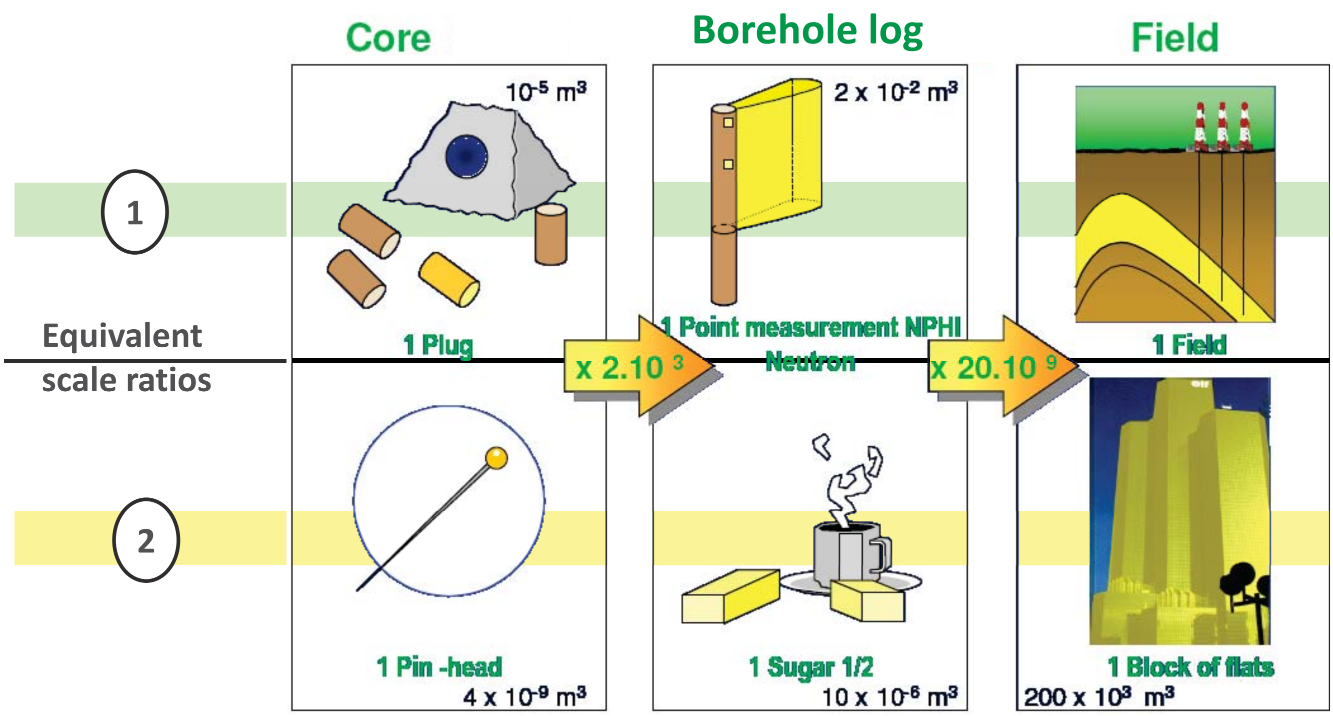


Understanding the data

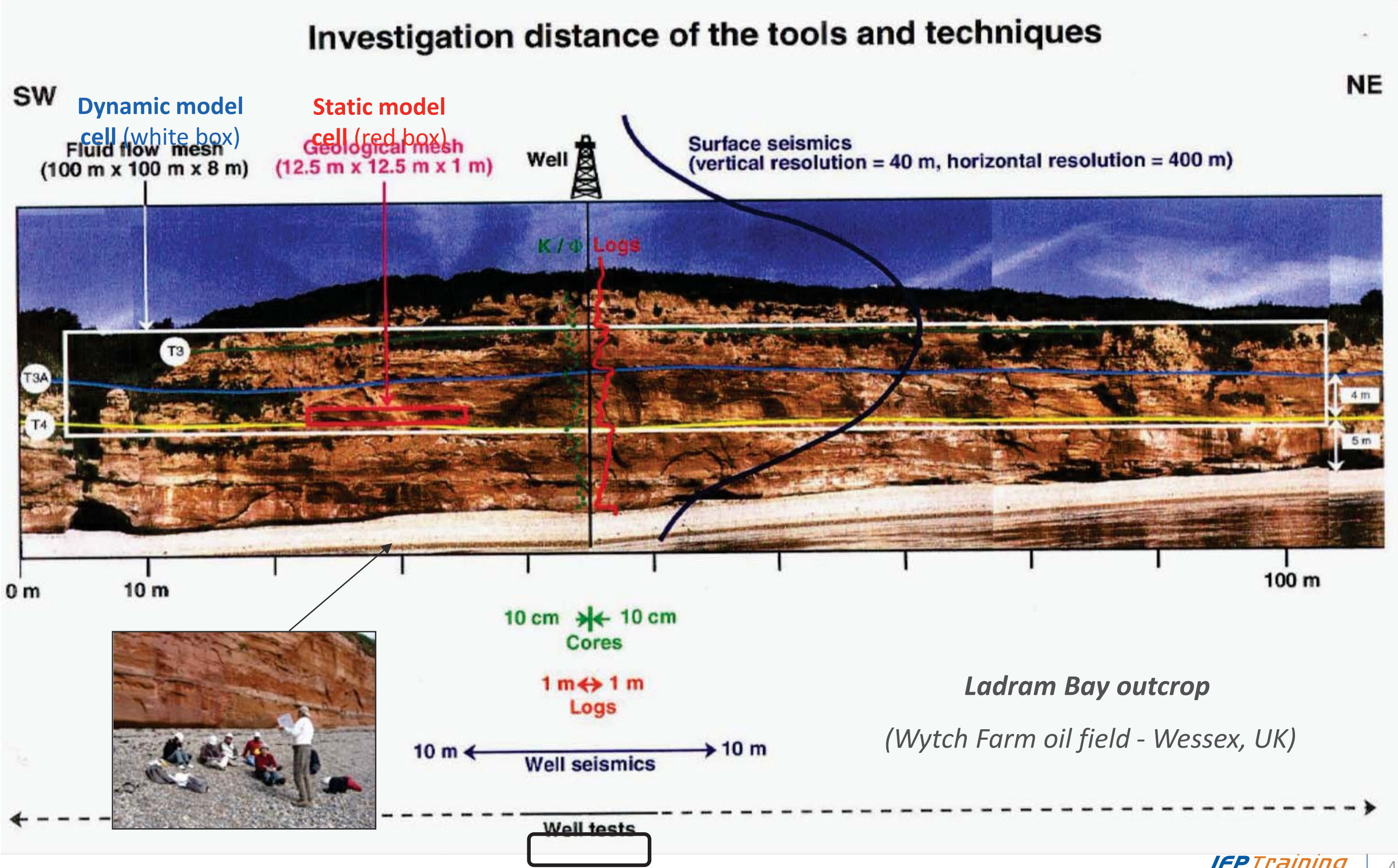
Data types and specificity

- **Different scales**
  - Plug data (5 cm) vs seismic bin (50 m)
  - K from logs vs [K.h] from well test
- **Different definitions**
  - Seismic data: **good lateral** definition but **poor vertical** resolution
    (1 sample every 10 m)
  - Well data: dense vertical sampling but very local (laterally limited)
    (1 sample every ft or ½ foot)
- **Different interpretations**
  - Facies definition: Geology (lithoFacies) vs Petrophysics (PetroFacies)

Scale ratio of data sets



Comparing scales



Ladram Bay outcrop

(Wytch Farm oil field - Wessex, UK)

Quality control

QC: Work with all your colleagues! (1/2)

- **Geophysicist**
  - Seismic data interpretation: faults, horizons, seismic facies,…
- **Log analyst**
  - Quantitative log interpretation: fluid contacts, petrophysical parameters…
- **Lab petrophysicist**
  - Petrophysical measurements on cores
- **Geochemist**
  - Analysis of fluids, rocks, organic matter
- **Sedimentologist**
  - Core analysis, well correlations, sedimentological model,…
- **Reservoir engineer**
  - Dynamic data synthesis, flow simulation

The reservoir geologist checks data consistency during the modeling phase.

He must work hand-in-hand with all stakeholders of the integrated study.

→ The success of the study relies on effective Team Work

QC: Work with all your colleagues! (2/2)

To build a reliable summary document:

- **Make a detailed inventory of available data**
- **Perform systematic, thorough data QC**
  - For a specific reservoir unit, a **good document** means a map with:
    - Seismic quality (area where seismic data is good, medium or bad).
    - Core quality
    - Always quality…

The reservoir geologist highlights areas where data are missing, or where they are of poor - or even bad - quality.

→ QC = first step for managing uncertainty

Quality control

Types of uncertainty

- Uncertainties on data
- Uncertainties on interpretation (results)
- Uncertainties on characterization (synthesis, integration)
- Uncertainties on modeling (concept, numerical values)

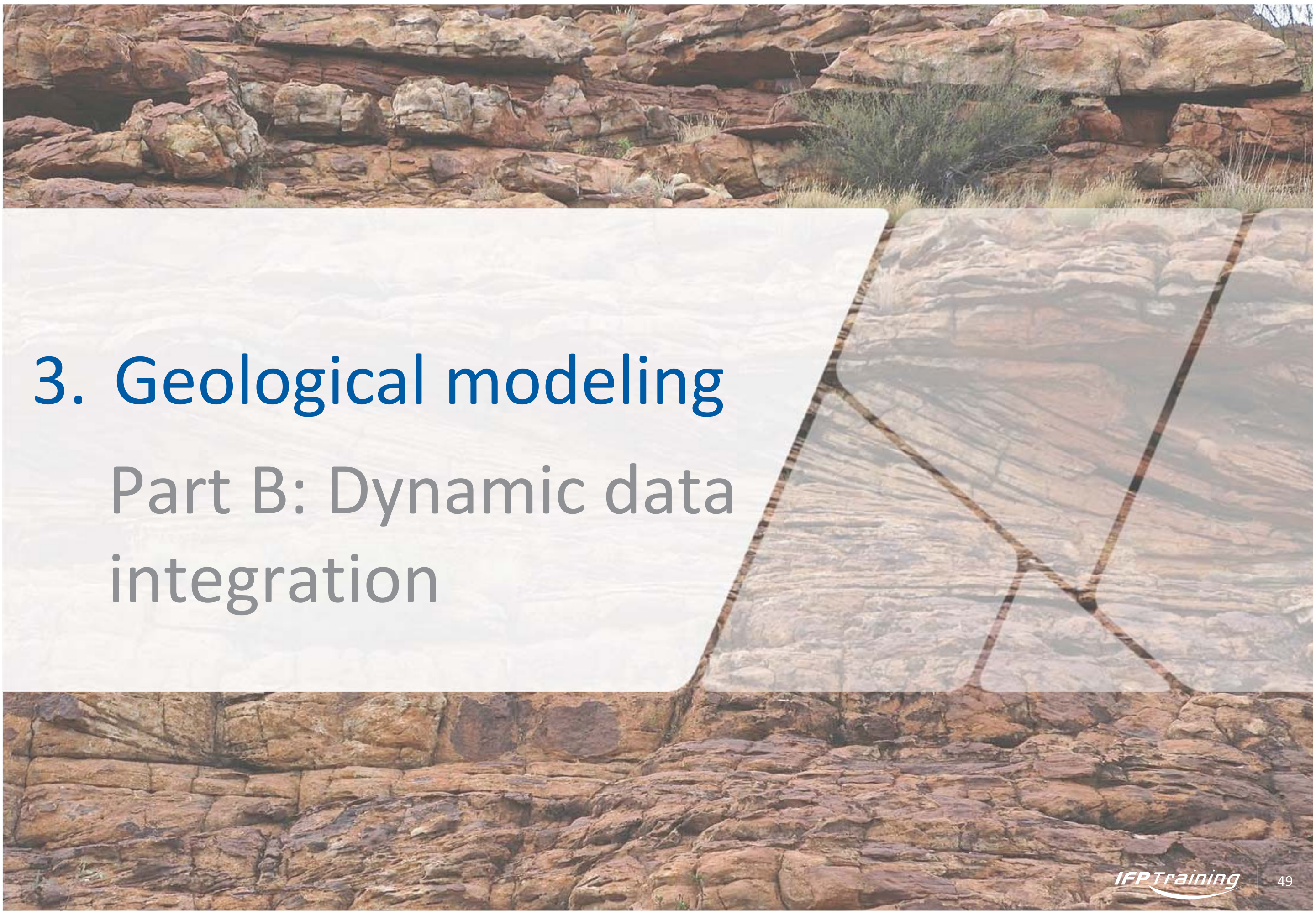
✓ Acquisition
✓ Interpretation
✓ Integration
✓ Computation

→ Uncertainties are additive!

Data integration for characterization - Key points

- **In an integrated reservoir study:**
  - **Data** are of various:
    - ✓Origins/Types
    - ✓Scales/Density
    - ✓Amounts/Volume
    - ✓Quality/Uncertainty
  - For each data type, specific **information** is gathered
    - ✓Some well intervals are cored, others are tested…
  - **Data** represent mainly **indirect** reservoir **information**
    - ✓Seismic data, Well logs, Dynamic data
    - ✓Direct access to reservoir: only through coring ("ground truth")
  - Data only represent a **small proportion** of the reservoir volume
    - ✓Among available data, well data are the most important (dense & accurate sampling)
  - Most crucial challenge: properly **integrate all information** within a consistent and relevant model – and reconcile all data types

➢ **Upscaling**
➢ **Geostatistics**



3. Geological modeling

Part B: Dynamic data integration

Course summary

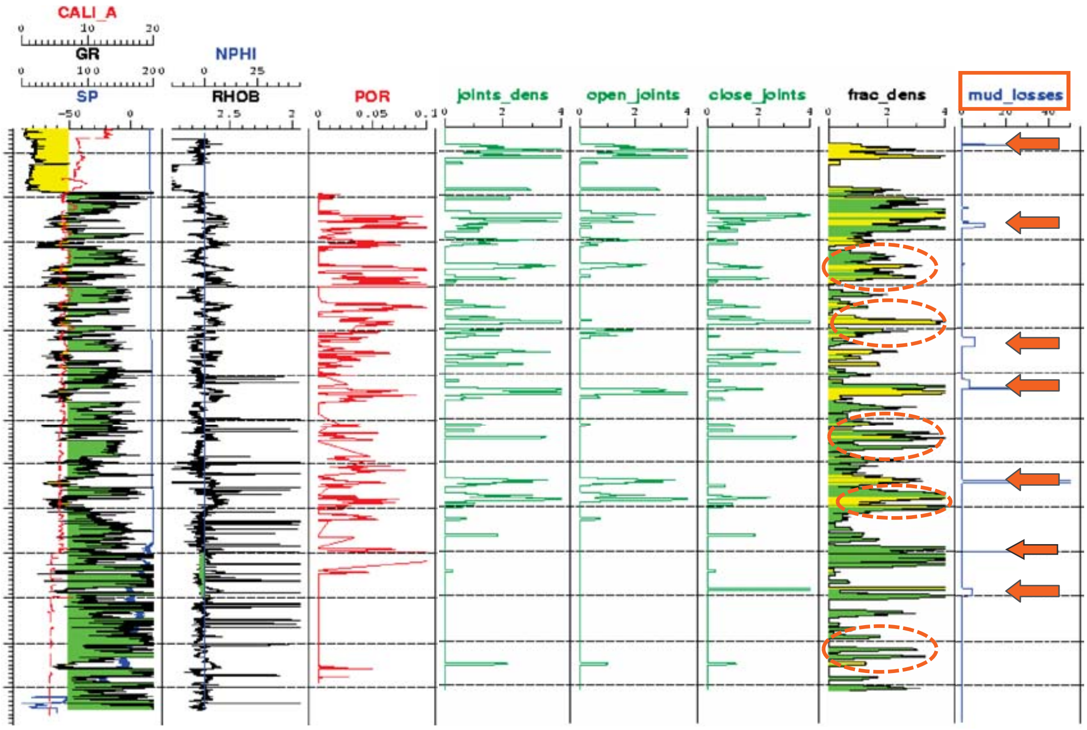
- **Identification of reservoir heterogeneities based on dynamic data**
- **Dynamic data integration to enhance character detection**
  - Mud losses (drilling report)
  - Flowmeters (PLT)
  - Pressure measurements
  - Well test analyses
  - Production history (volumes) and water-cut evolution

Dynamic data for characterization

Identification of heterogeneities affecting fluid flow

- **To identify compartments, first determine:**
  - Horizontal barriers (stacked reservoirs)
  - Vertical barriers: fault compartmentalization
- **To detect fluid flow anisotropy, first identify:**
  - Conductive faults
  - Fracture swarms
  - Channels

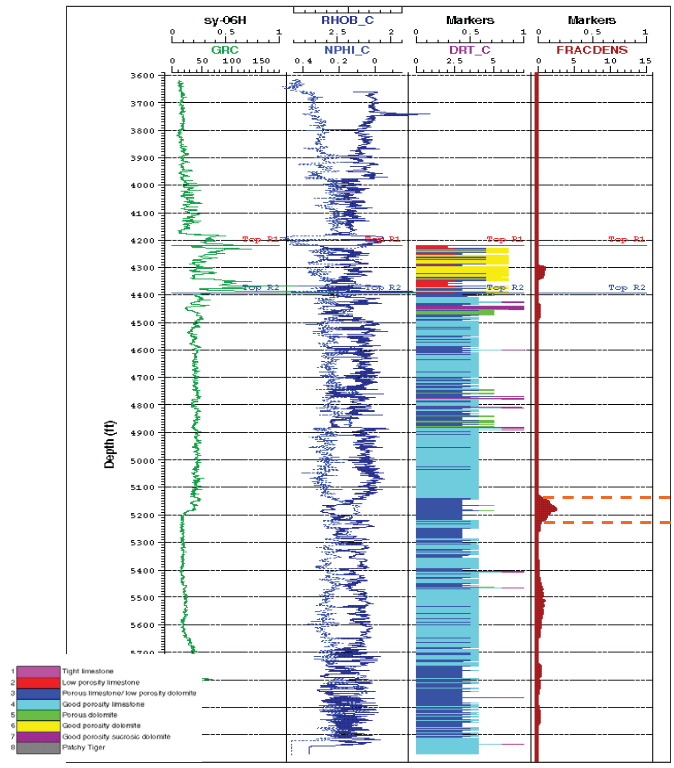
Mud losses analysis



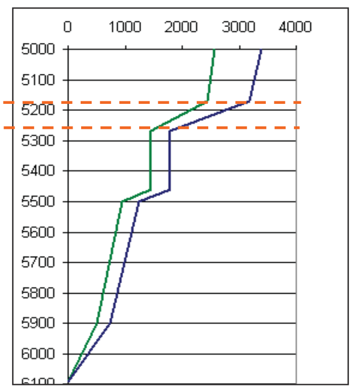
Karst? Channel? Open/Closed fractures? Fault?

Mud losses:

Fault conductivity from flowmeter (PLT)



C_F ~ 70 Darcy.m



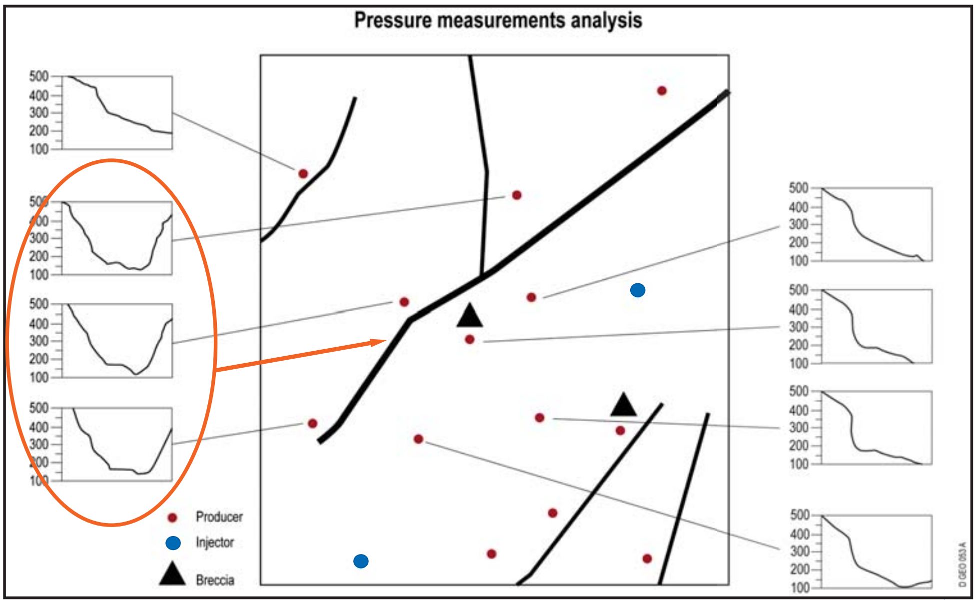
Start Poitiers exercise on PLT (Module 11)

Pressure measurements analysis

- **Identification dynamic barriers with pressure data**
  - Different pressure behavior between 2 groups of wells define a permeability barrier that can be correlated with the presence of a conductive fault
  - *Note: GOR and water break-through data can also be used to determine preferential trends of hydraulic flow*

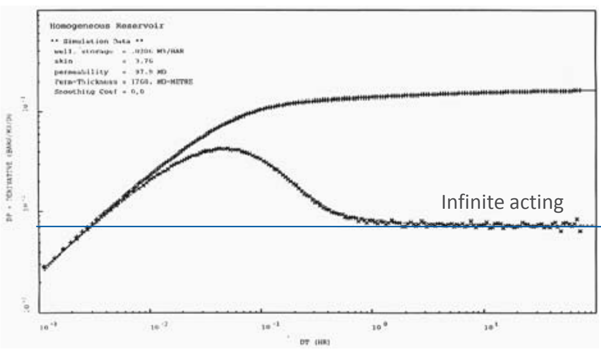
P^0 increase due to water injection conducted both by the fault and fractured zones

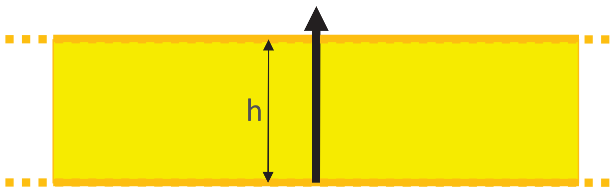
Breccia = fractures on cores



Well test patterns interpretation

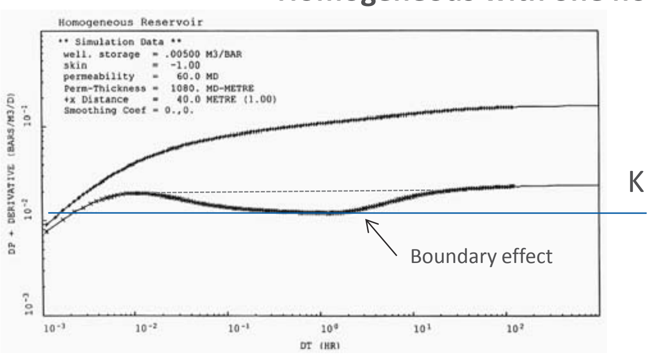
Homogeneous reservoir

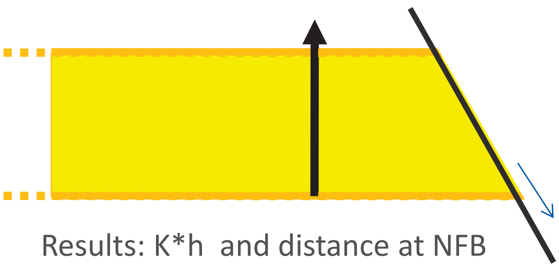




Results: K*h

Homogeneous with one no-flow boundary reservoir

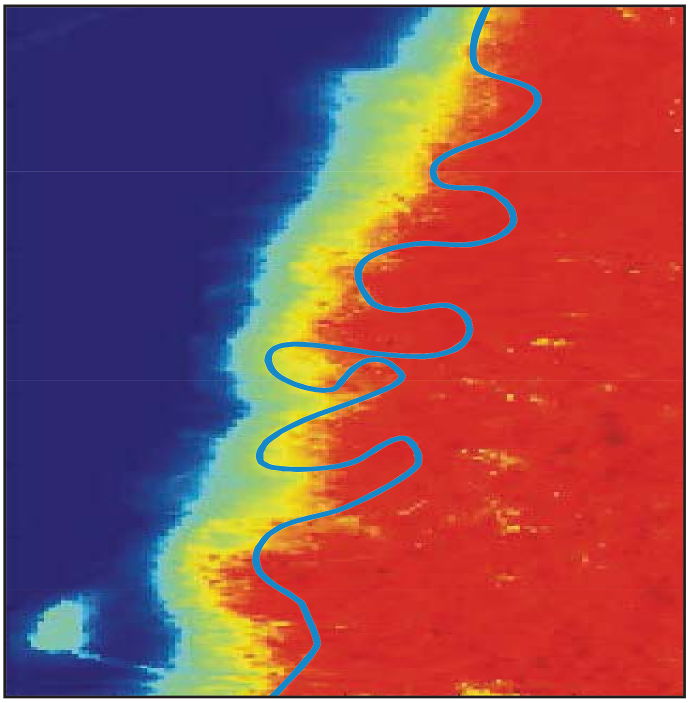




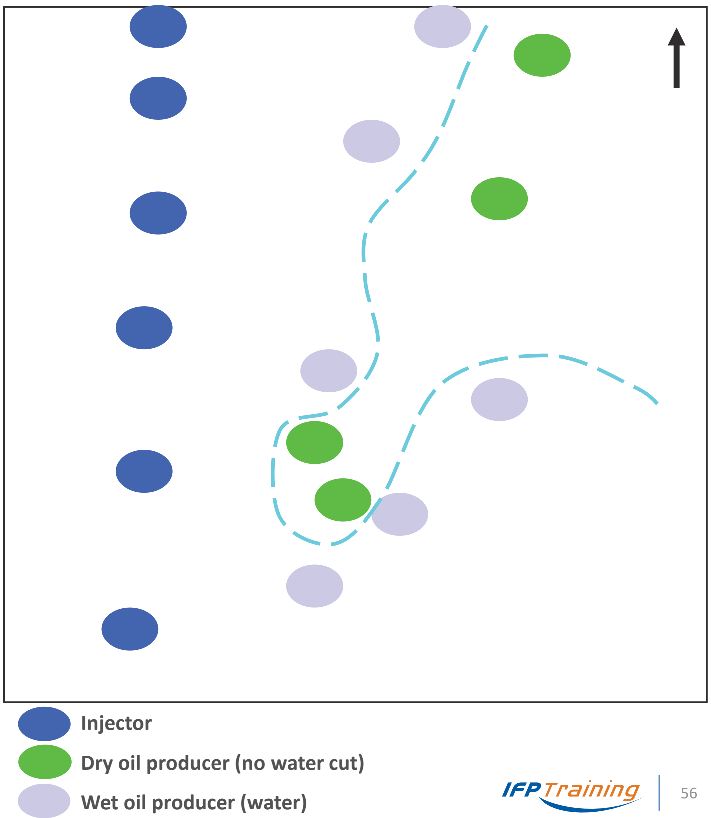
Results: K*h and distance at NFB

Production history and watercut analysis

Break-through analysis for fluid flow anisotropy detection



Fracture swarm identification



Dynamic data integration - Key points

- **Dynamic characterization is required to detect anomalies which impact fluid flow**
- **Identified anomalies are critical and must be incorporated into both:**
  - The **geological model**
  - The **reservoir model**
- **An integrated team for a reservoir study has a common objective: i.e. to build a conceptual model**
- **This model should integrate both sedimentological and structural elements in order to explain reservoir anisotropy regarding fluid flow**

4. Reservoir uncertainties

Course summary

- **Introduction to uncertainties**
  - Reservoir uncertainties
- **Uncertainties: two approaches**
  - Deterministic
  - Probabilistic
- **Managing uncertainty**
- **Reservoir model and uncertainties**
  - Structural uncertainties
  - Geological uncertainties
  - Dynamic uncertainties
- **Uncertainties in reservoir characterization**

4. Reservoir uncertainties

Uncertainties are to be considered

- **Uncertainties are everywhere!**
  - Complex physics
  - Lack of data
- **Not taken into account uncertainties can ruin a project**
  - Unexpected events…
  - → Should be defined by the team in charge of the project with the help of specialists

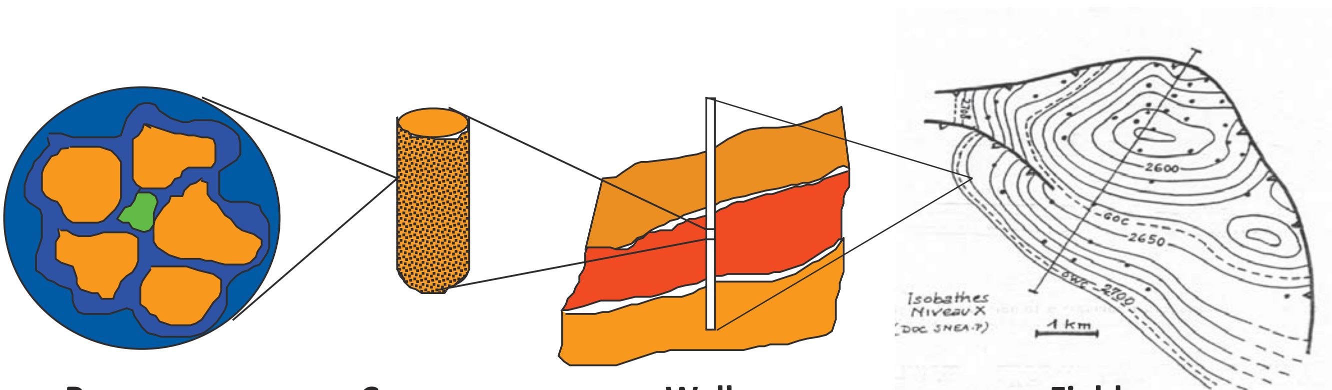
Assessing uncertainties

- **Unidentified or neglected uncertainties may result in a non-economic development**
- **One objective of reservoir monitoring is to help reducing dynamic uncertainties**

→ **Describing and understanding a reservoir is not an easy task (complex geology, data heterogeneity,...)**

Reservoir uncertainties

- **Uncertainties are related with:**
  - Available data (quantitatively- and qualitatively-wise)
  - Data interpretation
  - Reservoir heterogeneities
  - Scale changes



Pore scale	**Core** scale	**Well** scale	**Field** scale
1-100 µ	10 cm-10 m	50-500 m	1-100 km

Managing uncertainties

- **Uncertainties are present at each step of the workflow**
  - Seismic
    - Migration
    - Velocity model
    - Picking (faults & horizons)
    - Time-to-depth conversion
  - Geology
    - Sedimentological concept ; sedimentary bodies size, shape and distribution
    - Facies
    - Porosity, Permeability, Net thickness, Gross thickness, N/G, Sw…
    - Fluid contacts
  - Dynamics
    - Fault transmissivity
    - Faults: sealing or permeable, relative displacement
    - Compartmentalization (different pressures)
    - Permeability barriers extension
    - Kv/Kh
    - PVT: Bo, Bg, Rs
    - Fluid properties (gas, oil, water)
    - Kr

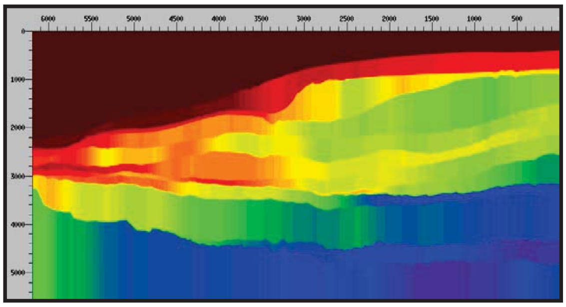
4. Reservoir uncertainties

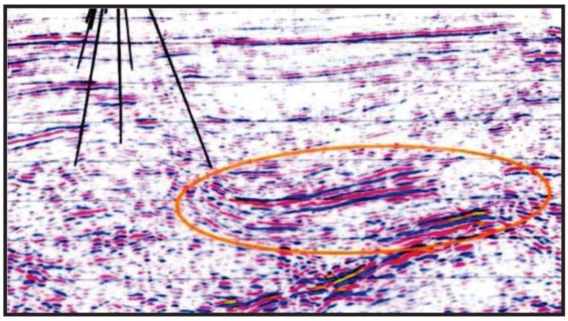
Introduction to uncertainties

Uncertainties in structural characterization

- **Main uncertainties in seismic data are related to:**
  - Processing
  - Well calibration
  - Interpretation
  - Depth conversion

Velocity section

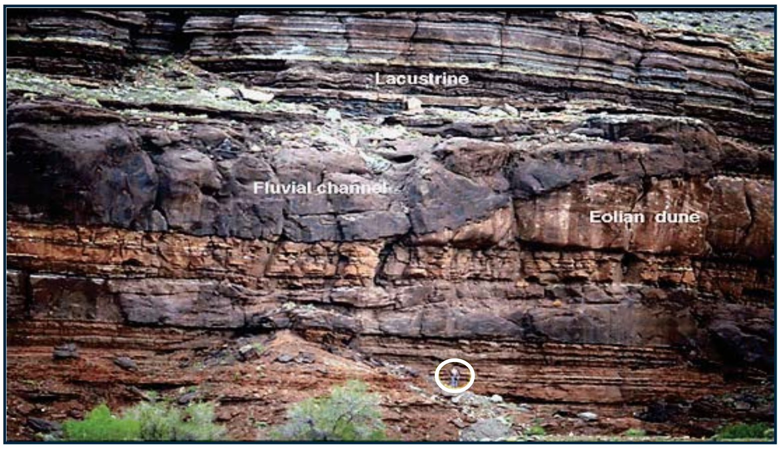




TWT section

Uncertainties in geological characterization

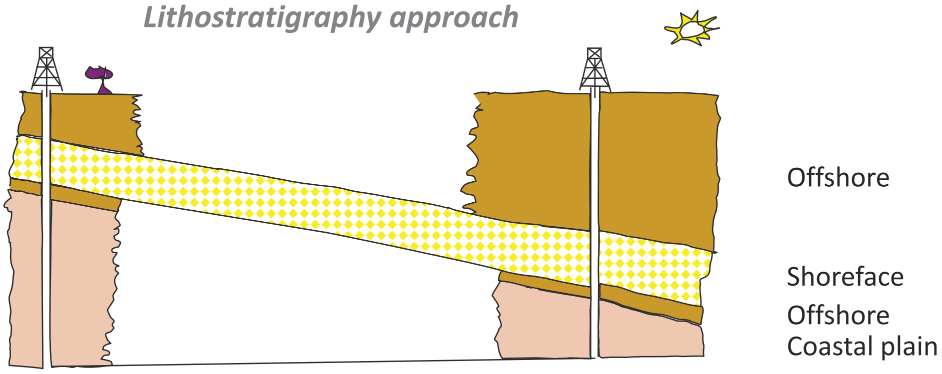
- **Main uncertainties in geological data are related to:**
  - Geological & sedimentological conceptual models
  - Petrophysical parameters:
    - porosity
    - N/G
    - fluid saturation
    - fluid contacts



A geological model must represent spatial variability

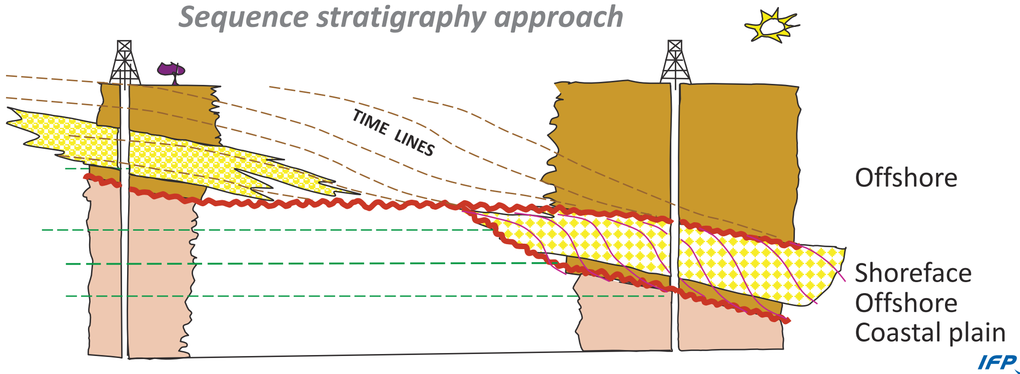
Uncertainties in sedimentological interpretation

Lithostratigraphy approach



Good facies analysis but wrong sedimentological model: beware of correlations!

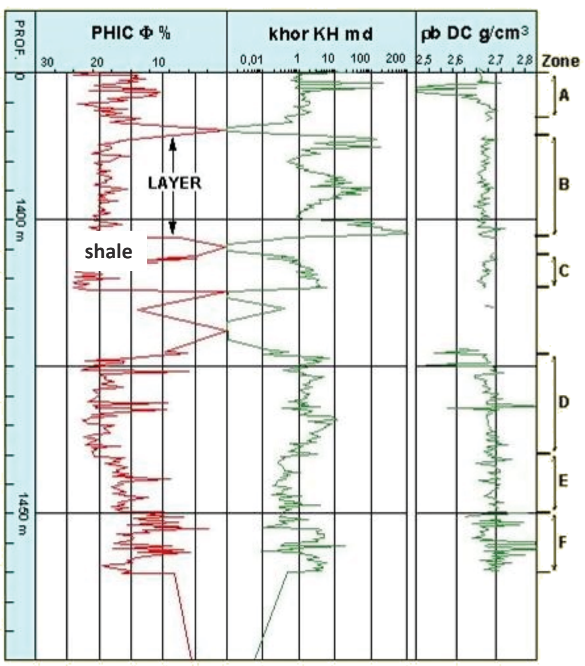
Sequence stratigraphy approach



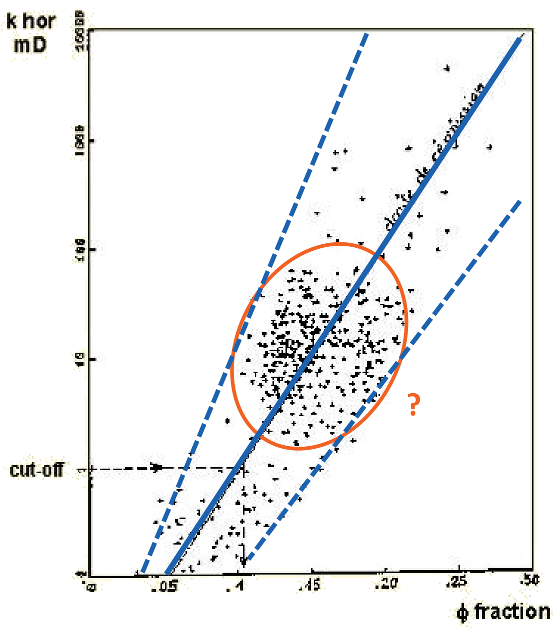
Uncertainties in petrophysical data

Uncertainty in petrophysical measurements

Core data



Log K vs Ø



Uncertainties in reservoir characterization - Key points

Geophysics	Geology	Res. Engineering
➢ Migration ➢ Velocity model ➢ Horizons picking ➢ Faults picking ➢ Time-to-depth conversion ➢ Well-to-seismic tying	➢ Structural and sedimentary concepts ➢ Extension and orientation of sedimentary bodies ➢ Distribution, shape, AE/RT limits ➢ Parameters: K, phi, NTG, Sw... ➢ Fluid contacts	➢ Fault transmissivity ➢ Extension of barriers ➢ Kv/Kh ➢ Viscosity, PVT ➢ Kr shapes and end points ➢ Aquifers ➢ Rock compressibility ➢ Well PI

- **In a model, details in excess are not a guaranty of precision:**
  - **Uncertainties are additive!**
  - → Reduce number of facies during geomodeling phase

5. Reservoir heterogeneities

Reservoir heterogeneities

Summary

- **Introduction: heterogeneities in the reservoir**
  - Homogeneous/heterogeneous reservoirs
  - Reservoir heterogeneity concepts
  - Classification of reservoir heterogeneities
  - Impact of reservoir heterogeneity on hydrocarbon recovery
- **Reservoir heterogeneity features**
  - Scale of reservoir heterogeneities
  - Small-scale observation and analysis
  - Large-scale observation and analysis

Reservoir heterogeneity: Concepts (1/2)

- **To build a consistent and relevant model:**
  - all variations in the reservoir quality must be analyzed and classified in a manner that the main heterogeneities main are clearly highlighted
  - for a given study, all heterogeneities that can affect fluid flow are considered as key heterogeneities

→ Key heterogeneities have to be absolutely described in the geological model

Reservoir heterogeneity: Concepts (2/2)

- **Reservoir heterogeneities**
  - All relevant factors affecting the dynamic behavior of the field
  - Small- to large-scale geologic features
  - From static reservoir characterization (significant or not)
  - From dynamic reservoir characterization (significant)
- **Basic principle**
  - Identify the smallest element that might impact production

Reservoir heterogeneities characterization calls for the cooperation between all professionals involved in the study (i.e. from geophysicists to reservoir engineers)

Reservoir characterization and modeling - Key points

- **To build a consistent and relevant model for an integrated study:**
  - All reservoir heterogeneities must be identified and classified (main ones highlighted)
  - All heterogeneities that can impact fluid flow are considered as major heterogeneities
  - Even the smallest elements that can affect production need to be identified and modeled
  - The geological model must take into account all significant heterogeneities
  - Characterization of reservoir heterogeneities calls for integrated multi-disciplinary approach (cooperation and team work)

Fundamentals of Reservoir Engineering – Petrophysics

Week#2

PTTEP Algeria

November 2016

Outline

1. **Introduction**
2. **Structure and properties of porous materials**
   - Porosity
3. **Statics of fluids in porous media**
   - Saturations - capillary pressure
   - Wettability
4. **Dynamic measurements**
   - Permeability
   - Relative permeability

1. Introduction

Definitions

- **PETROPHYSICS**: study of rock properties and their interactions with fluids (water solutions, liquid hydrocarbons, gases) (Archie, 1950)

- **Accumulation**: volume of hydrocarbons in place to be estimated, i.e. Hydrocarbon deposit (**reported in STANDARD Conditions**)

  (Original Oil in Place: OOIP)

  (Initial Gas in Place: IGIP)

- **Reserves**: Part of this volume that can be recovered by technical and economic procedures.

- The reserves are defined as the estimated quantities of crude oil, natural gas, gas condensate, liquids recovered from natural gas, and associated substances, that are considered commercially viable to recover from a given accumulation, **beginning at a certain future date, under specified economic conditions, using current technology, and subject to present-day legal restrictions**

Purpose

- **Accurate knowledge of petrophysical properties is required for:**
  - Calculation of the accumulations and the reserves
  - Efficient development of the oil field
  - Oil field management
  - Prediction of future performance

- **The behavior of a specific reservoir can only be predicted from:**
  - Analyses of the petrophysical properties of the reservoir
  - Fluid/Rock interactions from samples of the reservoir

Sources of rock properties measurements

Coring / logging / well testing

- **Well logs: continuous but indirect measurements of properties at in-situ conditions**
  - Porosity (measure nuclear or sonic property, infer ϕ)
  - Saturation (measure electrical property, infer S_w)

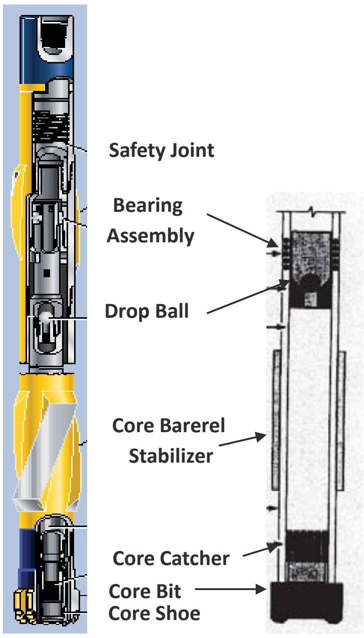
- **Core analysis: more direct but discrete measurements of properties in the laboratory (may attempt to reproduce in-situ conditions)**

- **Well tests: discontinuous and indirect measurements**

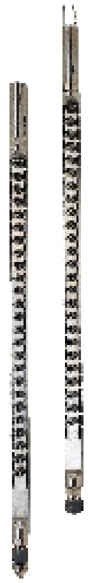
Coring

How to take cores

Core Barrel



Sidewall Corgun™ (SWC)



- Core Diameter 0.85 in. (21.6 mm)
- Core Length 2.5 in. (63.5 mm)
- Maxi Pressure 20 000 psi (137.9 Mpa)
- Maxi Temp 400 °F (204 °C)

Sidewall Coring Tool (RCOR ℠)

Bit section of Rotary

Samples

Core Specifications

- length 1.75 in (44.5 mm)
- diameter 1 in. (25.4 mm)
- capacity 30

Coring

Diamond core bits

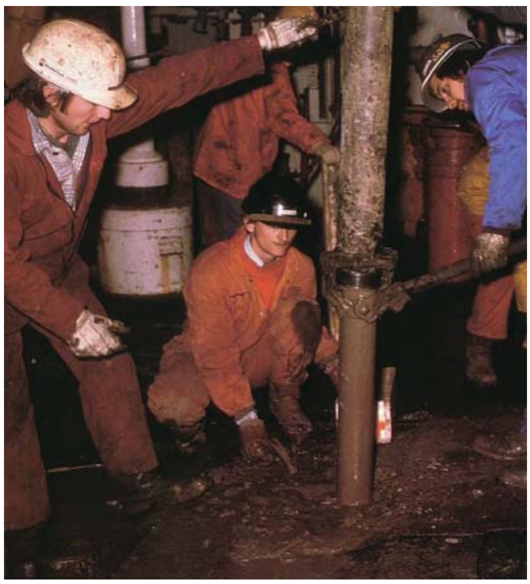
PDC

Poly-Cristallin Diamond

TSD

Thermal Stabilized Diamond

DIAMOND

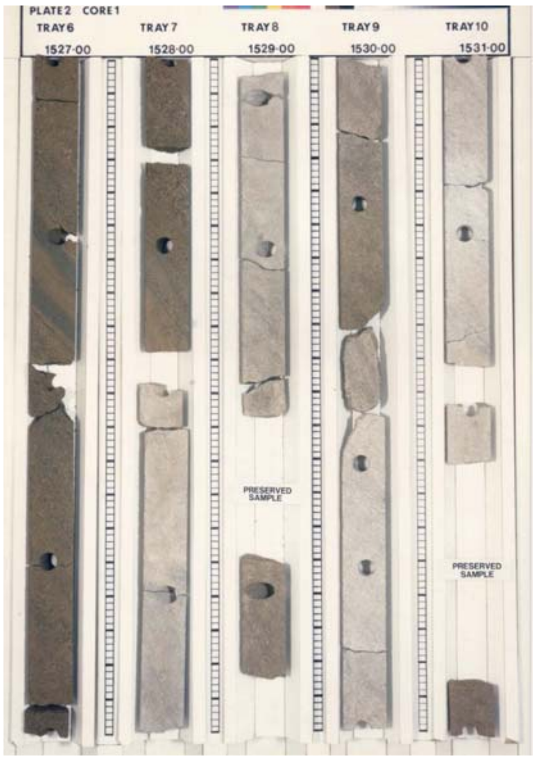


Core studies

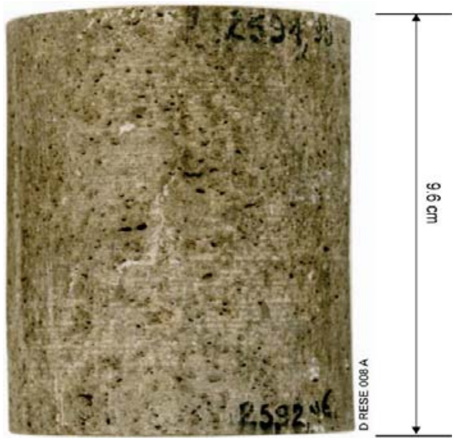
- **Geology**
  - Lithology: mineralogy – facies – depositional environment
  - Chronostratigraphy: datations
  - Dip, fracturation
  - Geochemistry
- **Petrophysics**
  - Φ – Porosity
  - K – Permeability
  - S_w – Saturation
- **Log core correlation**

Cores

Corebit



Lithofacies vs. Petrofacies – Core examples



Lithofacies: Dolomite with vugs
Characteristics: small vugs
Φ= 14,6 %
K= 0,6 mD

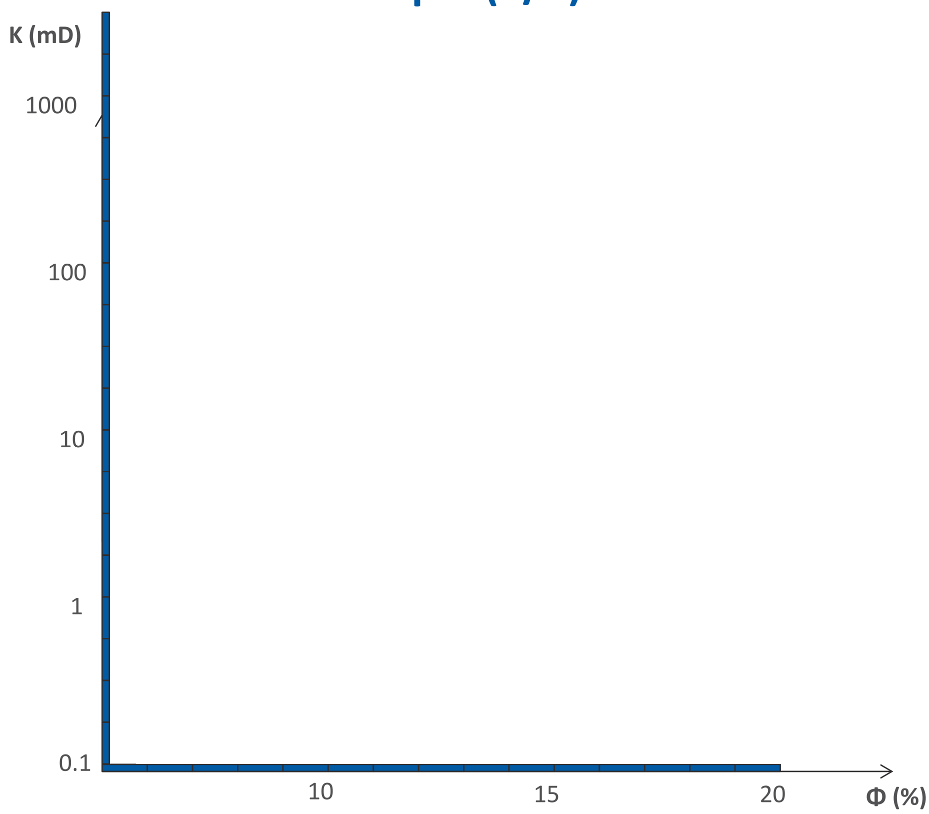
Lithofacies: Dolomite with vugs
Characteristics: Intermediates vugs
Facies: mixed
Φ= 18,8%
K= 134 mD

Lithofacies: Dolomite with vugs
Characteristics: Large vugs
Φ= 20,1%
K= 1.5 D

Same LithoFacies! …but… same PetroFacies?

Core studies

Lithofacies and Petrofacies – example (2/2)



2. Structure and properties of porous materials

Porosity

Porosity

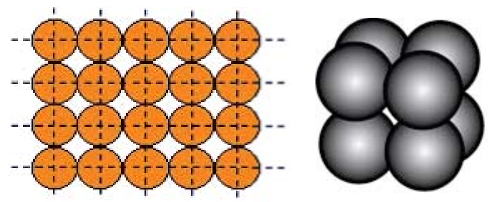
Porosity ϕ

ϕ = Pore volume / Total volume

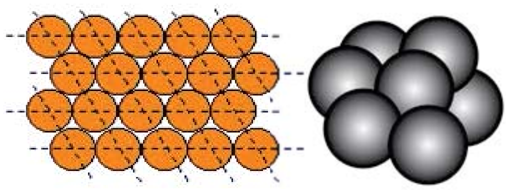
(common values 0.01 to 0.35)

Important parameters

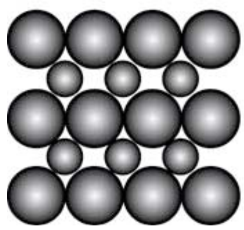
- Grain shape & organization
- Grain sorting & distribution
- ϕ is not related to grain size (for same size spherical grains)



Cubical packing
(1 size)
Φ = 47.6%



Rhombohedral packing
Φ = 25.9%

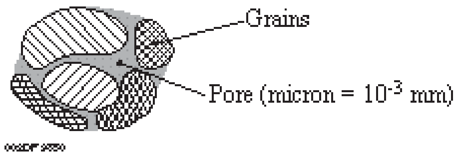


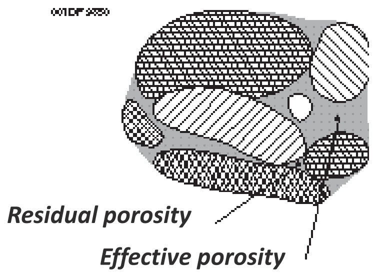
Cubical packing
(2 sizes)
Φ = 12.5%

Porosity values are measured on cores and extracted from logs

Porosity

ϕ: Fraction of the bulk volume of the material occupied by voids





$$\phi = \frac{V_P}{V_B} = \frac{Pore\ Volume}{Bulk\ volume}$$

$$\phi = \frac{V_B - V_S}{V_B}$$

$$V_S = Volume\ of\ solid$$

Usually 5% < ϕ < 30%

Porosity

% pores (voids) in a solid rock

$$\Phi = \frac{\text{Vpores}}{\text{Vtotal}} = \frac{\text{Vtotal - Vsolids}}{\text{Vtotal}}$$

Φeffective → **Lab** Φeffective = Φtotal

Φtotal → **Log**

Interconnected voids:
→ **effective porosity**
Non-connected voids:
→ **residual porosity**

Φ < 5%	**Low: tight carbonates**
10% < Φ < 20%	**Average**
Φ > 20%	**High: unconsolidated sand/chalk**

Matrix porosity → average Φ of fractures < 1% (negligible)

Porosity measurement

- **The weighting technique**
  - P_1 = weight of the dry sample
  - P_2 = weight of the brine saturated sample

    $P_2 - P_1 = \rho_w \times V_{pores}$

    V_{total} from the sample dimensions (diameter, L)

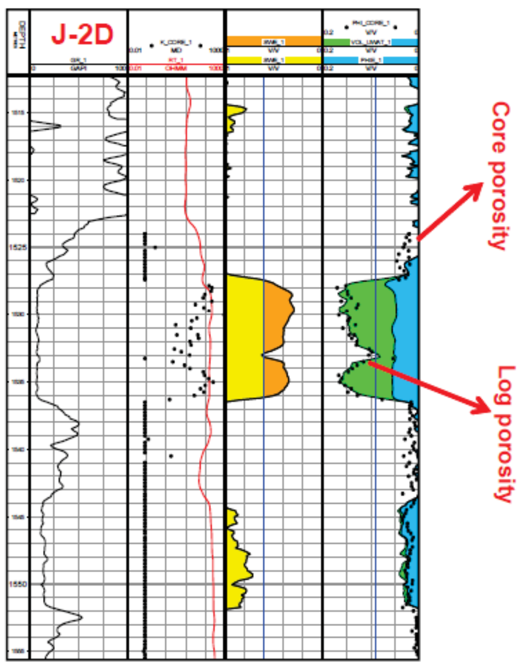
- **Density Method**
  - $m = \rho_S V_S = \rho_B V_B$, $\varphi = 1 - \dfrac{\rho_B}{\rho_S}$, $m =$ mass of sample

- **Direct Method**
  - Crushing of samples
  - Heating to extract the fluids

- **Mercury injection**
  - V_{total} by immersion, V_{pores} by injection

Model properties

- **POROSITY**
  - Core vs. Log porosity
  - Differences may be due to nature of measurements: effective porosity vs. connected one
  - In general, should correlate well in most wells
  - A good correspondence (as in this case) increases confidence in the model adequacy
  - If sufficient core data was gathered, then the core porosity profile may be used to condition the model (log profiles are used most commonly)



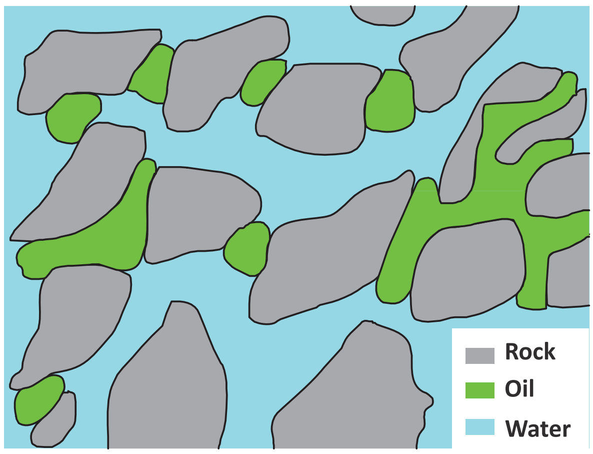
3. Statics of fluids in porous media

Saturations – Capillary pressure

Wettability

Saturations

- $V_{pores} = V_{water} + V_{oil} + V_{gas}$
- **Normalization with V_{pores}**
  - Notion of saturation
    - $S_w = V_w / V_p$
    - $S_o = V_o / V_p$
    - $S_g = V_g / V_p$
- $S_w + S_o + S_g = 1$



Residual oil bubbles trapped behind the water front

- **Objective**
  - To determine S_o and S_g every where in the reservoir to calculate Oil and Gas volumes

Example of porosity and saturation

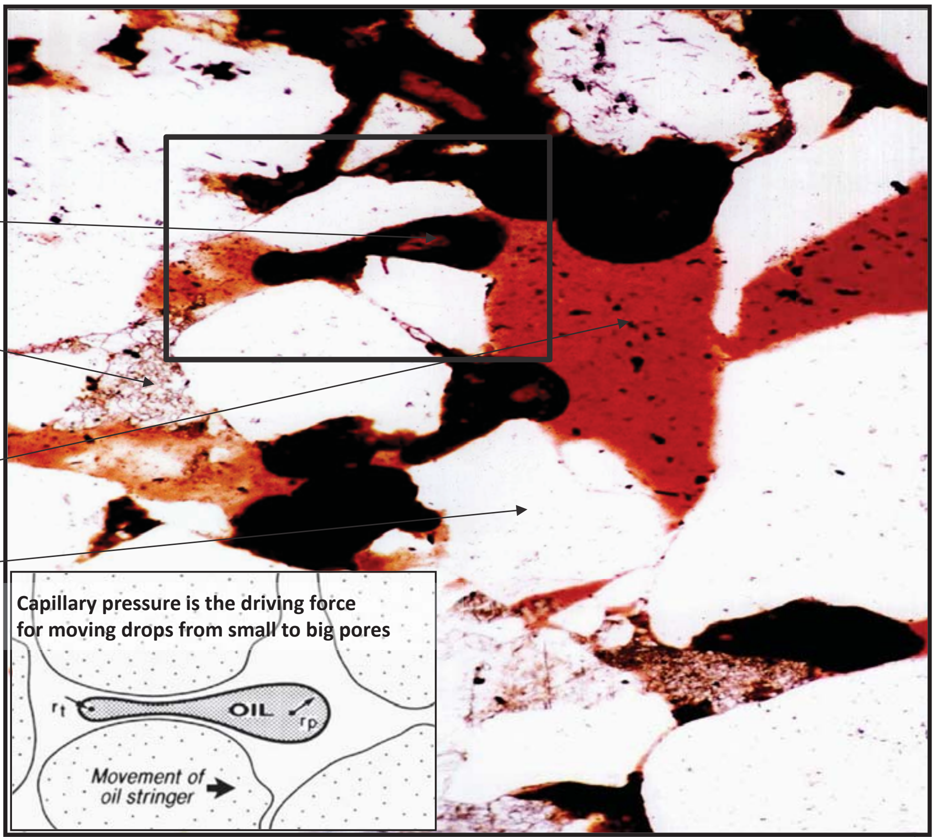
Oil-impregnated sand reservoir

Oil blob

Shale

Water (resin)

Grain (quartz)

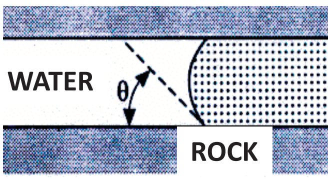


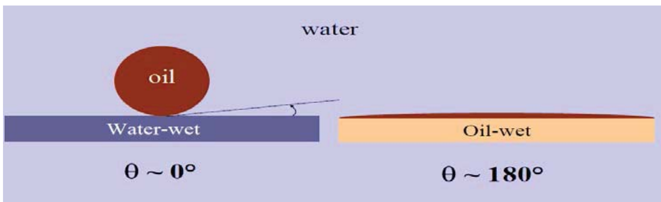
Thin section (~ 2 cm)

Wettability

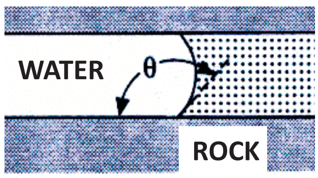
- **Definition**
  - **Tendency of one fluid to spread on a surface in presence of another fluid. It determines the contact angle**
  - Wettability is a function of surface chemistry (**fluids-rock interaction**)

Water-wet system





Oil-wet system



- **Wetting fluid: contact angle Θ < 90°**
- **Wettability to oil due to polar components in oil or to adsorbed products on the rock surface**
- **In a rock/brine/oil system wettability measures the preference that the rock has either for oil or water**

Wettability of a porous medium

- **The wettability determines which fluid will be in contact with the rock surface**
  - Water-wet rock: water covers the rock surface, oil occupies the bulk of large pores
  - Oil-wet: oil covers the rock surface, water occupies the bulk of large pores
  - Intermediate-wet or neutral-wet: no preference for either fluid
  - Mixed-wet or fractional-wet: continuous parts of the solid surface are water-wet, others oil-wet

- **The wettability plays a major role on the fluid distribution within the pore structure. Thus it affects**
  - Relative permeabilities
  - Capillary pressures
  - Residual Saturations

Gas is always a non-wetting fluid

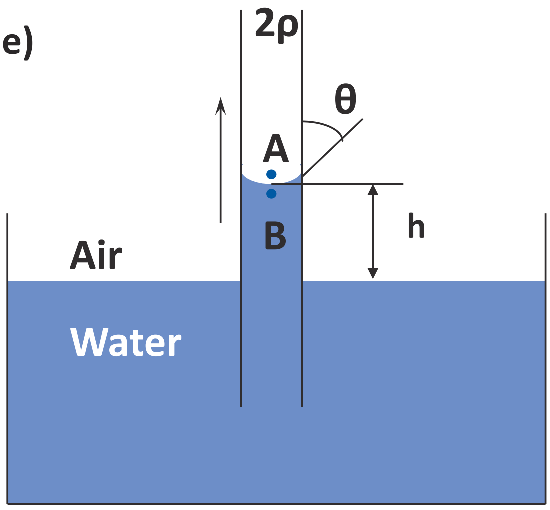
Notion of capillary pressure

YOUNG – LAPLACE Equation (for a capillary tube)

$$P_c = P_A - P_B = \frac{2\,\sigma\cos\theta}{r}$$

$$P_B = P_{atm} - h\,(\rho_w - \rho_{air})\,g$$

$$P_c = h\,(\rho_w - \rho_{air})\,g$$



- **Depends on**
  - Wettability (θ)
  - Pore diameter (2ρ)
  - Interfacial tension (σ)

- **The capillary pressure corresponds to the pressure difference between two fluids in equilibrium in a capillary tube**
- **Capillary pressure = pressure difference in capillary medium between the non-wetting fluid and the wetting fluid**

Fluid level references in a reservoir

- **Threshold P_c**: value at which oil first enters pores (**S_w<1**) [P_c displacement]
- **Free water level** (**FWL**): depth at which **P_c= 0**
- **Oil-water contact** (**OWC**): depth below witch no oil can be found

Transition zone

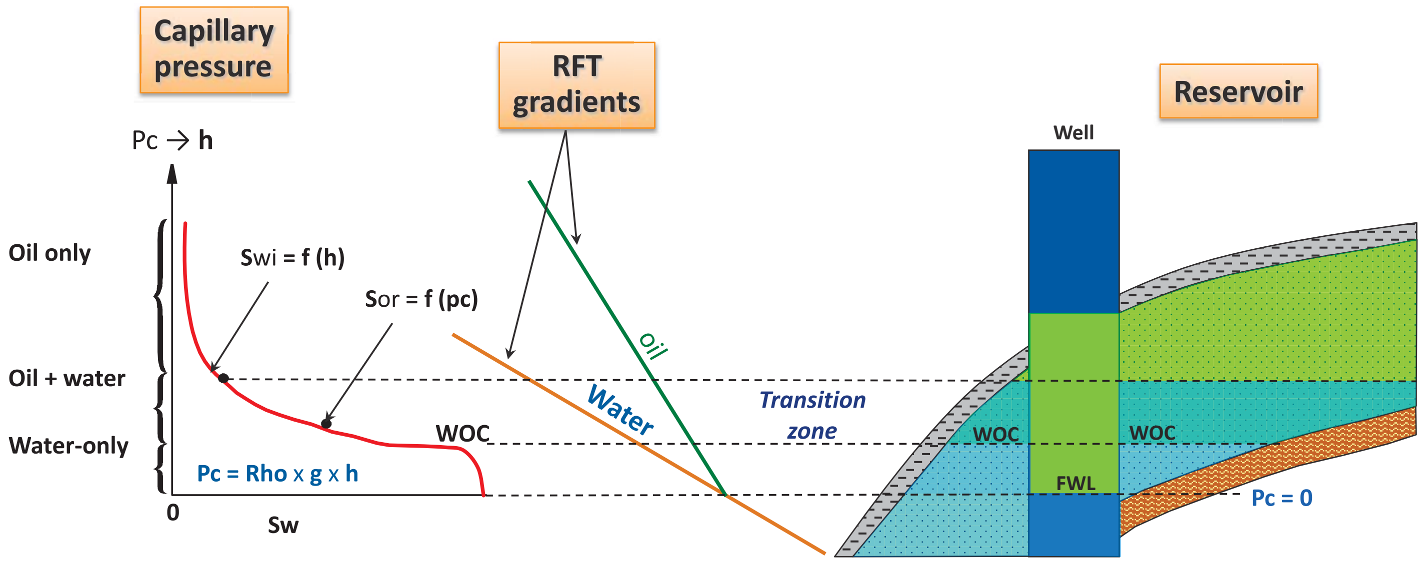
- **Evaluation from a Pc curve**
  - P_c obtained in laboratory
- **Correction for reservoir conditions**
  - $P_c(h) = \Delta\rho \times g \times h$ from (zero P_c depth)
  - $P_c(S_w)$ known

→ **$S_w = f(h)$**
accumulations

If reference depth is FWL → $P_c = \Delta_\rho \times g \times h$

If reference depth is WOC → $P_c - P_{cd} = \Delta_\rho \times g \times h$

Fluid contacts

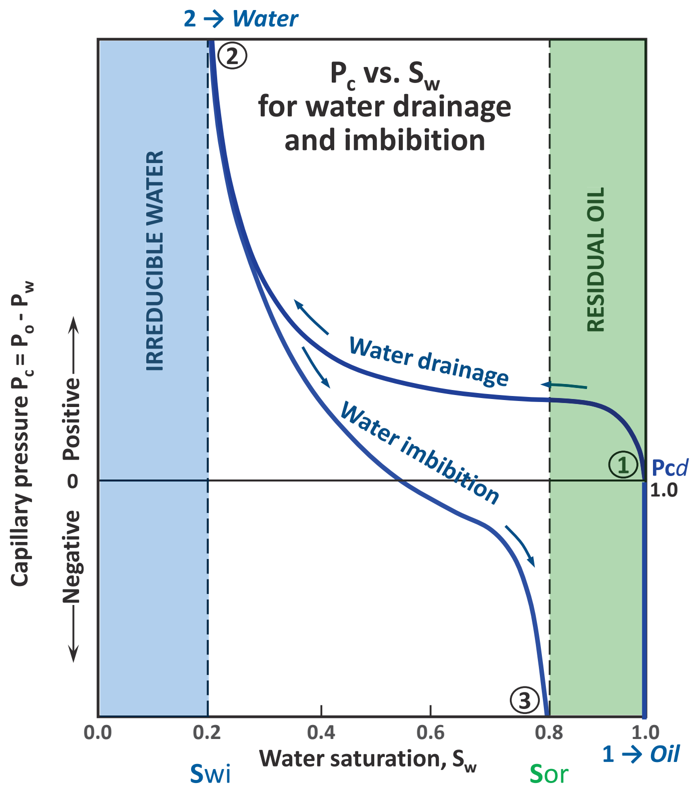


RFT / MDT → FWL
LLD / MSFL → WOC

FWL = **Free Water Level** → **Pc = 0**
WOC = **Water-Oil Contact** → **Displacement pressure (Pc*d*)**

Capillary pressure curves

- Capillary pressure curves define the **relationship between capillary pressure and water saturation** from laboratory tests on reservoir core samples
- If the test is performed with a **non-wetting fluid (oil) displacing a wetting fluid (water)**, it is called a **drainage** capillary pressure curve
- If the test is performed with a **wetting fluid (water) displacing a non-wetting fluid (oil)**, it is called an **imbibition** capillary pressure curve



Key points to keep in mind

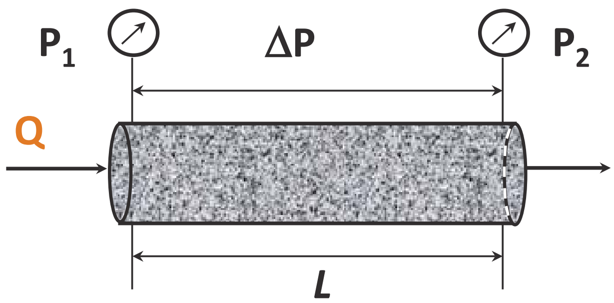
- **Saturation – Capillarity**
- **Fluid saturation**
  - The ratio of the fluid volume to the total pore volume
  - In the reservoir $\mathbf{S_w + S_o + S_g = 1}$
- **Interfacial Tension IFT**
  - The surface energy existing between two immiscible fluid phases
  - The greater the IFT, the less miscible the two fluids
  - Oil-water is an immiscible system
- **Capillary Pressure**
  - Young – Laplace equation: $\mathbf{P_c = \frac{2\sigma \cos\theta}{r} = P_{non\ wetting} - P_{wetting}}$
  - Depends on wettability, pore diameter and IFT
- **Drainage: displacement of wetting fluid by non-wetting fluid**
- **Imbibition: displacement of non-wetting fluid by wetting fluid**

4. Dynamic measurements

Permeability

Permeability

- **Measures the capacity and ability of the formation to transmit fluids**



1 Darcy

cm³/sec

$1\,cp = \frac{1}{100} \times \frac{dyne \times sec}{cm^2}$

cm

$$k = \frac{Q\mu}{A} \times \frac{L}{P_1 - P_2}$$

cm^2

$1\,atm = 1.033\,kg/cm^2$

Darcy's Law

μ:	Fluid Viscosity (cP)
Δ P:	Differential Pressure (atm)
A:	Cross sectional area (cm2)
Q:	Injection flow rate (cm3/s)
L:	Length (cm)

K in Darcy=0.987 10^{-12} m^2

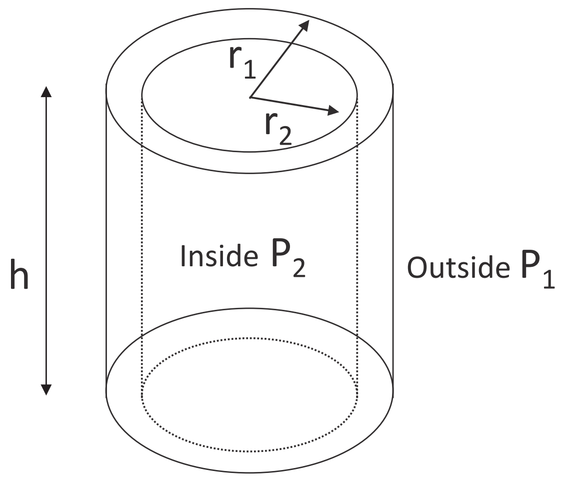
Typically: 0.1 < K < several Darcy

Permeability

- **Sandstones**
  - Tight sands: K< 1 mD
  - Sandstone (shaly to not shaly): 0.1 à 100 mD
  - Clean sandstone: several hundreds md
- **Unconsolidated sandstones**
  - K> 1 Darcy: function of grain size
- **Carbonates**
  - Compact carbonate: K<1 md (dolomite and limestone)
  - Vuggy dolomite: 1 à 200 mD
  - Compact limestone (K matrix<0.1 MD): production only due to fractures.

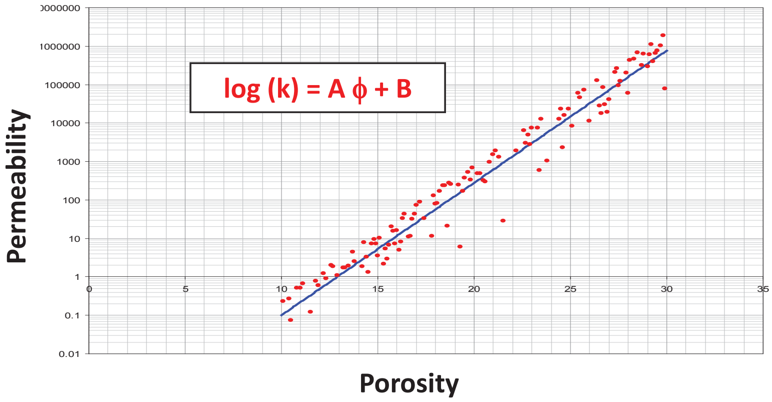
Radial flow

Q:	**Flow Rate**
r1:	**Drainage radius**
r2:	**Well radius**
P1, P2:	**Pressures**
h:	**Thickness**
μ:	**Viscosity**
K:	**Permeability**

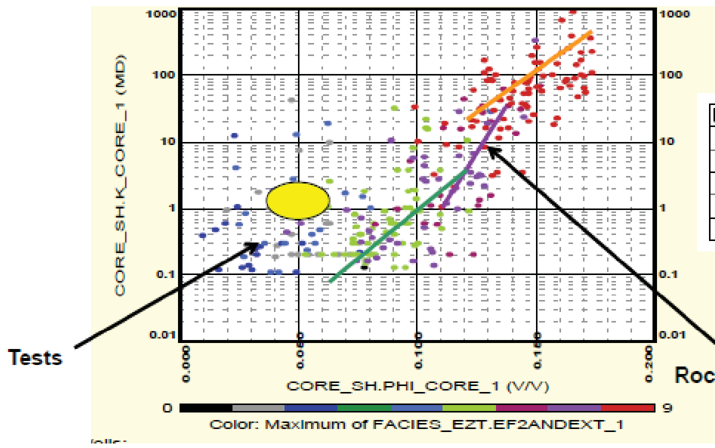


$$Q = \frac{2\pi hK}{\mu} \frac{P_1 - P_2}{Ln \dfrac{r_1}{r_2}}$$

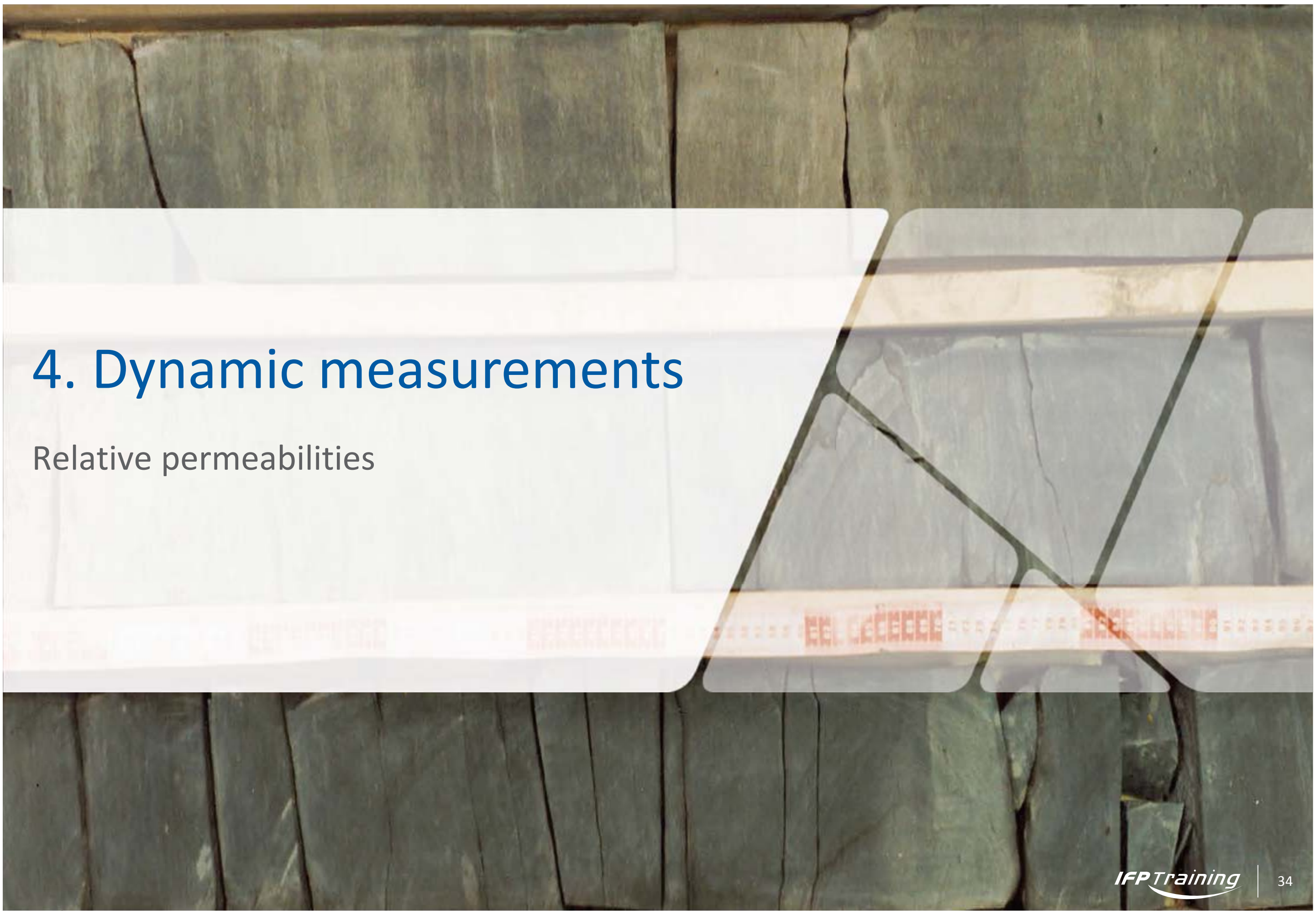
k-ϕ correlation



k = permeability (millidarcys)
ϕ = porosity (fraction)
A, B = Constants



Permeability-Porosity equations		
log K = a * Porosity + b		
Facies	a	b
5 and 6	19,86	-2,15
7 and 8	37,82	-4,06
9 (10)	20,21	-1,19

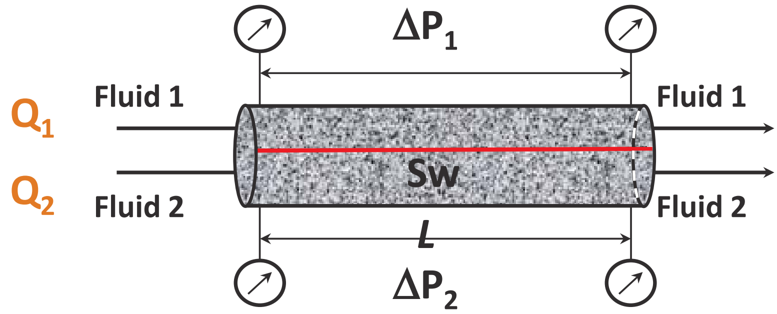


4. Dynamic measurements

Relative permeabilities

Effective permeability: definition

- By analogy with steady-state immiscible flow



$$Q_1 = \frac{k_1\, A\, \Delta P}{\mu_1 L}$$

$$Q_2 = \frac{k_2\, A\, \Delta P}{\mu_2 L}$$

k_1 effective permeability to fluid 1
k_2 effective permeability to fluid 2
k_1, k_2 depends on saturation in fluid 1 & 2
same unit than k_a

- **Definition of effective permeability to one fluid: Measure of the ability of the porous system to conduct one fluid in presence of other fluids**

Relative permeabilities: definition

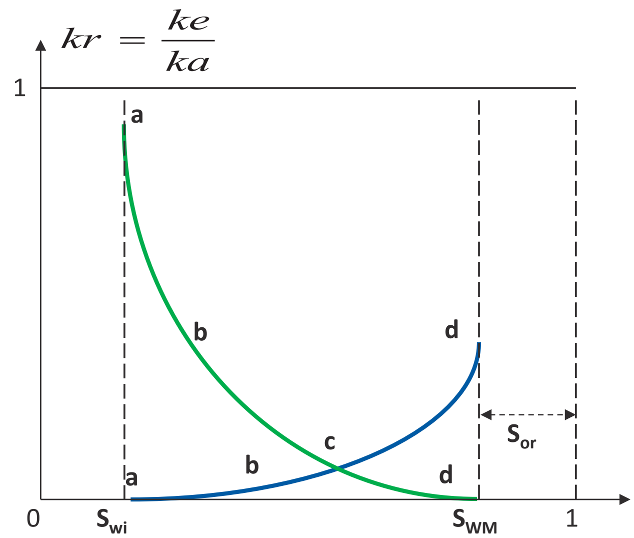
- **Absolute permeability:**
  - Permeability of rock saturated completely with one fluid: K_{air}, K_w

- **Effective permeability:**
  - Permeability of rock to one fluid; when the rock is only partially saturated with that fluid: $K_{o(sw)}$, $K_{w(oil)}$

- **Relative permeability:**
  - Ratio of effective permeability to some base value

$$K_{ro} = \frac{K_{o(sw)}}{K_{(swi)}} \qquad K_{rw} = \frac{K_{w(sw)}}{K_{(swi)}} \qquad K_{rg} = \frac{K_{g(sw)}}{K_{(swi)}}$$

kr – Example oil/water



a: only oil is moving: kro=1 & krw=0

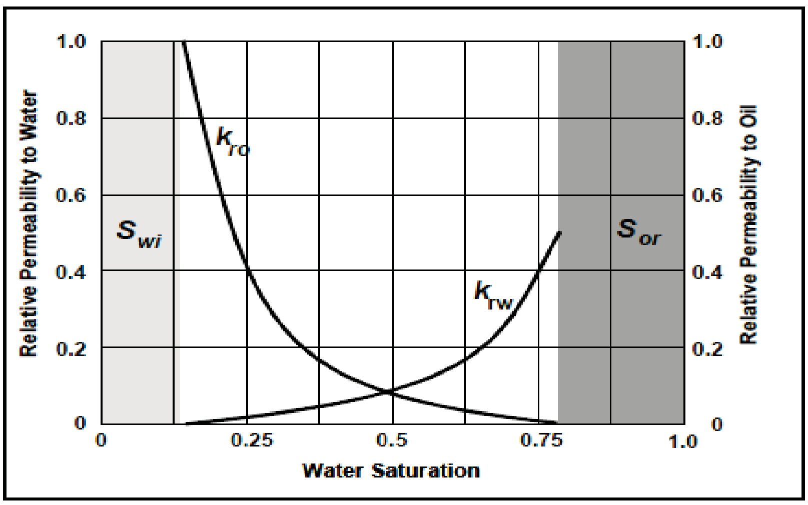
b: Sw ↗, oil flows less easily

c: kro=krw and kro+krw < 1
k two phases < k one phase

d: oil is not mobile any more
(So=Sor), krw(Sor) < 1

- Except for end points, the sum of relative permeabilities is always strictly lower than one
- Those curves dictate flow of oil and water in the reservoir

Impact of wettability on relative permeability Kr



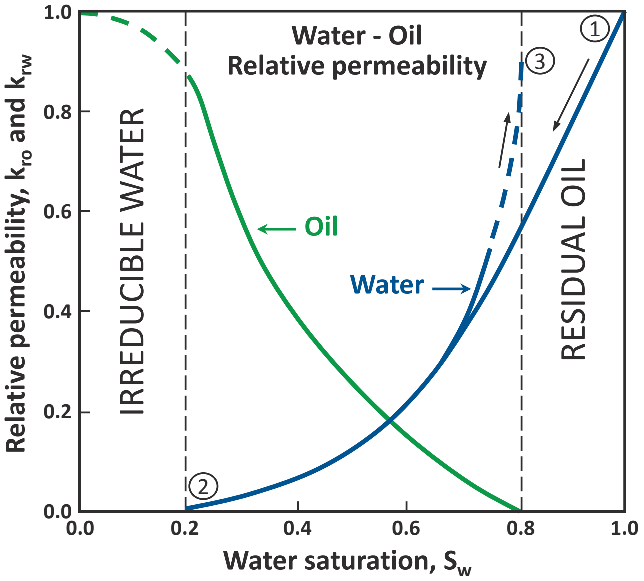
→ K_{ro} decreases when S_w increases

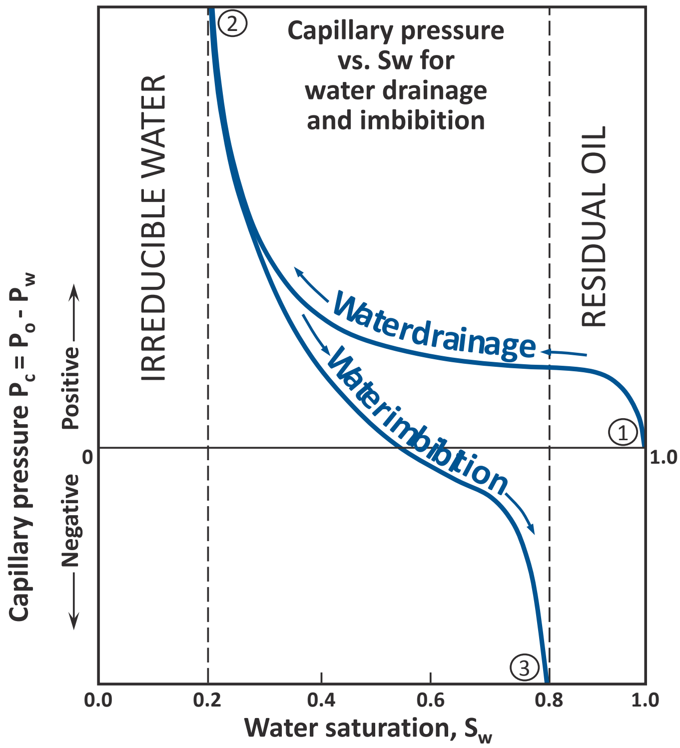
→ increasing water cut reduces permeability to oil

→ Water-wet: K_{ro} is higher for same S_w (0.2)

→ Oil-wet: K_{rw} is higher for same S_w (0.8)

Saturation functions





Key points to keep in mind

Relative permeability

- **Relative permeabilities**
  - When two (or more) fluids flow simultaneously in a rock / in a reservoir, this results in permeability reduction for each fluid permeabilities
  - Depends on saturation
- **Relative permeability**
  - The ratio of effective permeability to absolute permeability
  - Absolute permeability is the permeability of the rock when totally saturated with one fluid
  - Effective permeability is the permeability of the rock when partially saturated with one fluid
- **Relative permeability**
  - Allows to generalize Darcy's law to multiphasic flows in the reservoir
  - Is defined by a curve as a function of saturation, typically $\mathbf{k_{ro}(S_w)}$ and $\mathbf{k_{rw}(S_w)}$
- **Relative permeability curves**
  - Depend on wettability
  - Rule flow of fluids (water and hydrocarbons) in the reservoir and have a strong influence on the Recovery Factor

Fundamentals of Reservoir Engineering – PVT

Week#2

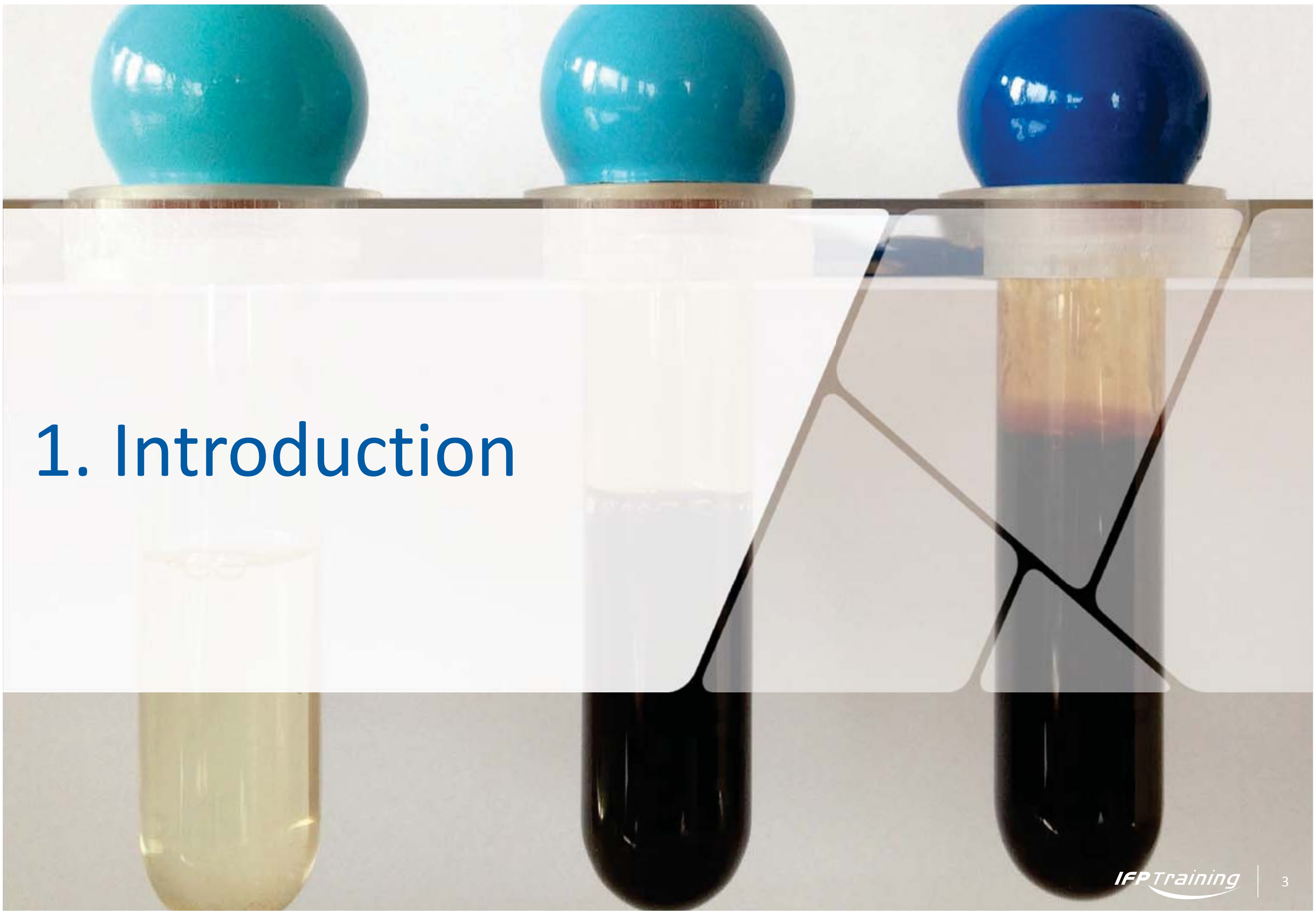
PTTEP Algeria

November 2016

IFP Training

Outline

1. Introduction
2. Pure components and simple mixture properties
3. Petroleum fluids classification
4. Main oil and gas properties
5. Reservoir fluid sampling
6. PVT studies



1. Introduction

Generalities

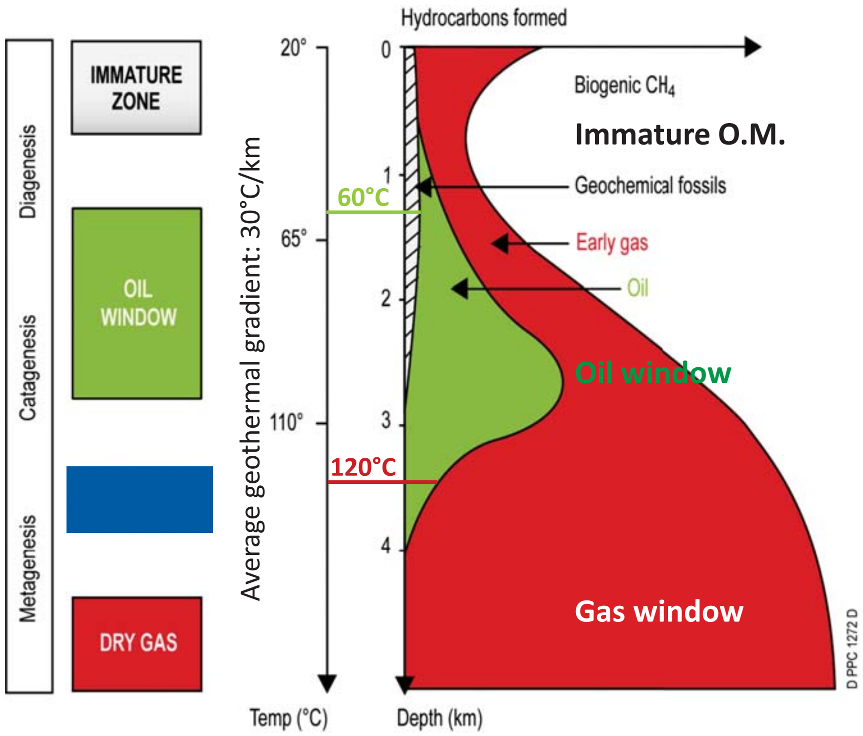
- **Reservoir fluids**
  - Hydrocarbon liquid (oil)
  - Hydrocarbon gas
  - Hydrocarbon solid (bitumen for example)
  - Non Hydrocarbon compounds (CO_2, H_2S, N_2…)
  - Water

- **Under Pressure (50-700 bar) and Temperature (30-170 °C) within the reservoir**

- **During the production process**
  - In the reservoir, P varies and T remains constant
  - From the hole to the tank, P and T vary

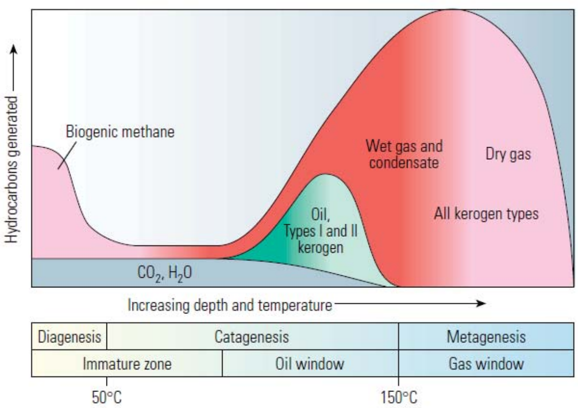
Transformation of O.M. & Kerogen

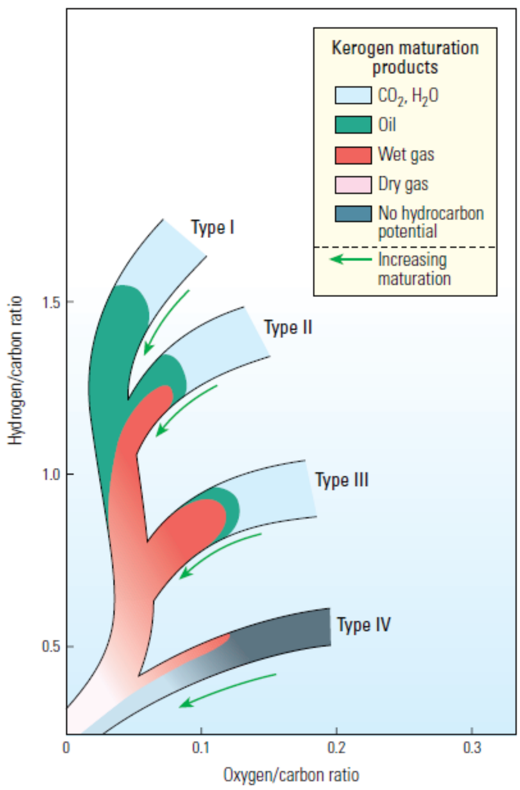
- **Diagenesis [< 60°C]**
  - Bacterial degradation
  - **Immature stage**
- **Catagenesis [from 60 to 120°C]**
  - Thermal degradation
  - →"weak" chemical bonds breaking
  - **Oil window**
- **Metagenesis [from 120 to 200°C]**
  - Thermal degradation
  - →"strong" C–C bonds breaking (cracking)
  - **Gas window**



Petroleum fluids genesis

- **Kerogen conversion to hydrocarbons. The Van Krevelen diagram: H/C vs. O/C**
- **The green arrows show the evolutionary paths**



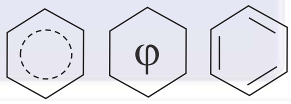


Components of reservoir fluids

HYDROCARBONS
H-C

ALIPHATICS
$C_n H_{2n+2}$

AROMATICS

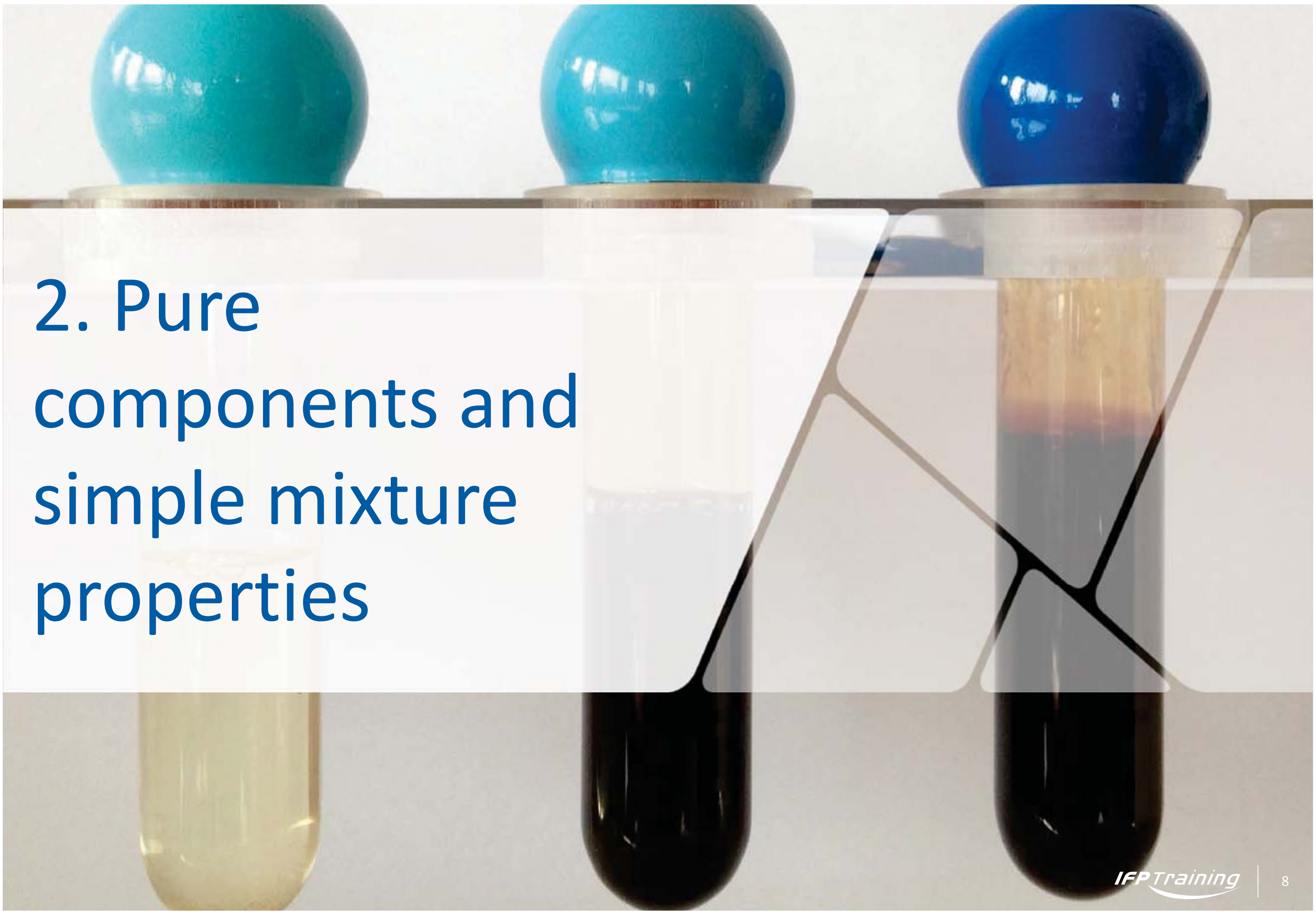


ALKANES or PARAFFINS
Straight chains: C_nH_{2n+2}
Branched chains: C_nH_{2n+2}

cyclo-ALKANES or NAPHTENES
C_nH_{2n}

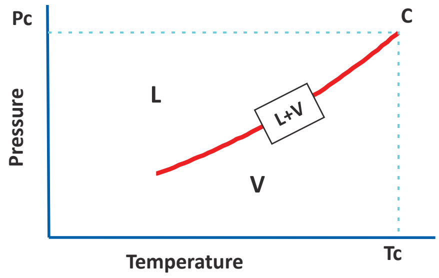
+

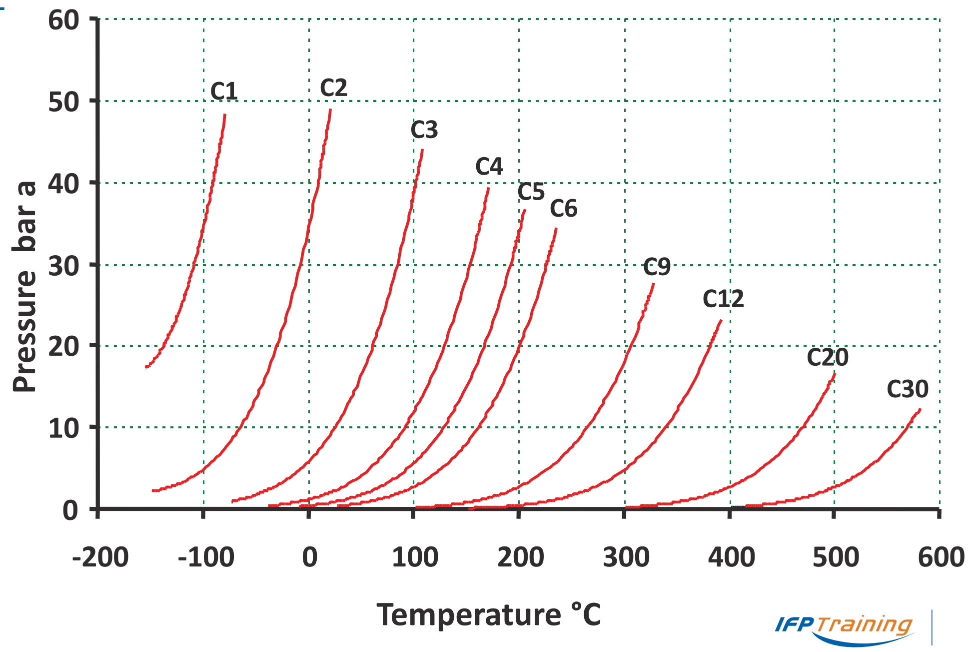
N_2, O_2, S
H_2S, CO_2
TRACE ELEMENTS:
Hg, Ni, Va, S, O…



2. Pure components and simple mixture properties

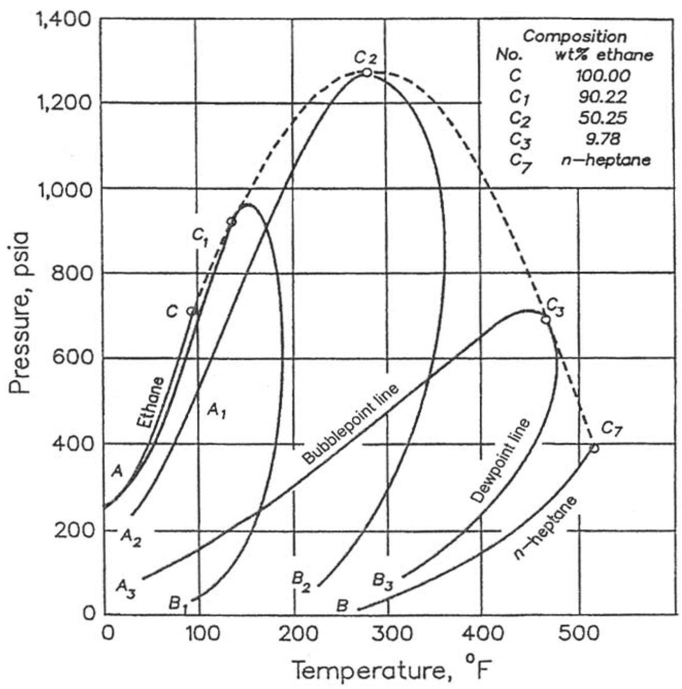
Liquide-Vapor equilibrium of several n-alkanes





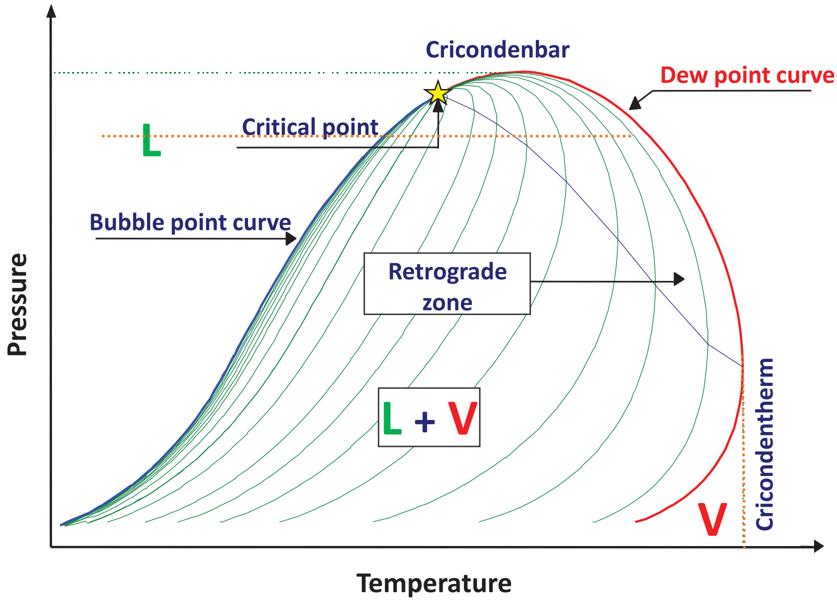
Binary mixtures properties

- **P-T diagram**
  - Example of the C2/n-C7 system at various concentration of C2



- **Mixtures of similar components have narrow phase envelopes**
- **Mixtures of dissimilar components have broad phase envelopes**

Phase enveloppe



Bubble point: condition at which an oil is in equilibrium with an infinitesimal amount of gas (pressure at which the first gas bubble appears)

Dew point: condition at which a gas is in equilibrium with an infinitesimal amount of oil (pressure at which the first liquid droplet appears)

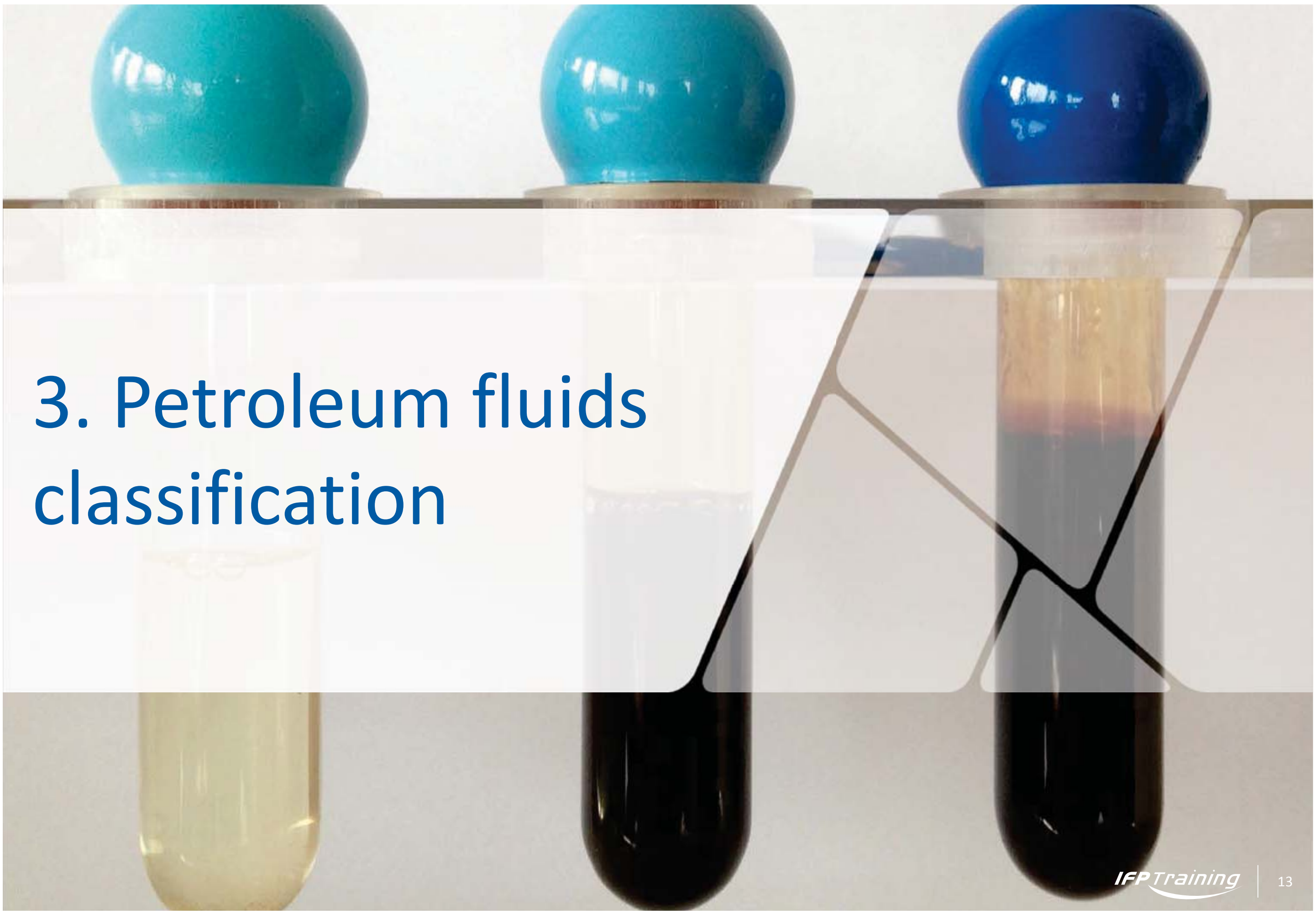
Saturation conditions: conditions at which one phase is in equilibrium with an infinitesimal amount of another phase

Definition

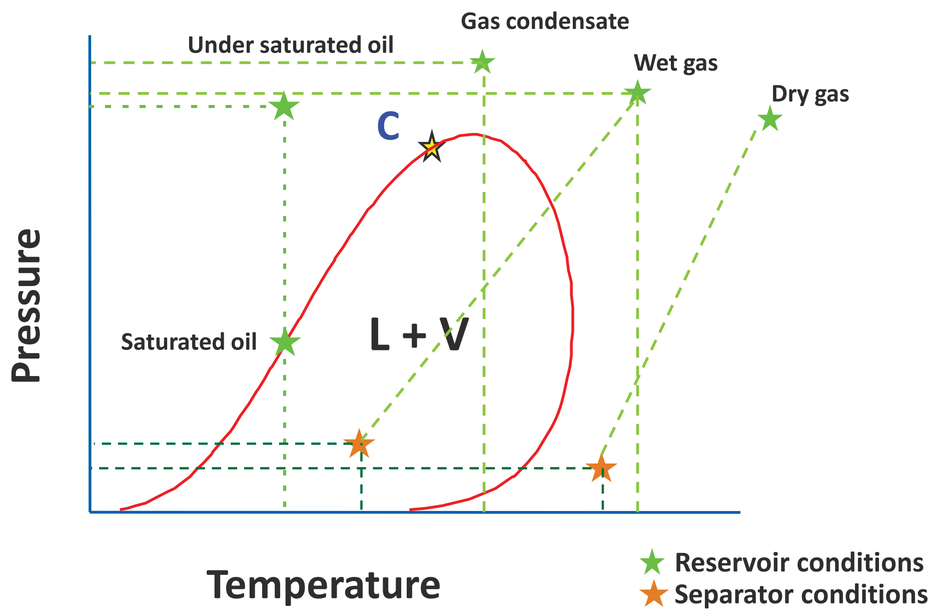
- **Oil**: reservoir fluid having a bubble point at reservoir temperature. When the pressure decreases in the reservoir, the fluid is monophasic until the bubble point pressure is reached. Below this pressure, a gaseous phase expands progressively
  Special case: a dead oil is an oil containing so little gas dissolved that no bubble point is noticeable. This is often the case with heavy oil

- **Gas**: reservoir fluid having either a dew point at the reservoir temperature (condensate gas), or no transition phase at this temperature

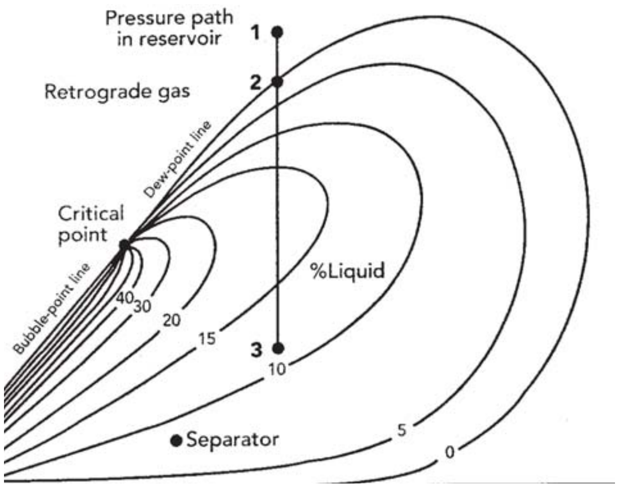
3. Petroleum fluids classification



Petroleum fluids classification



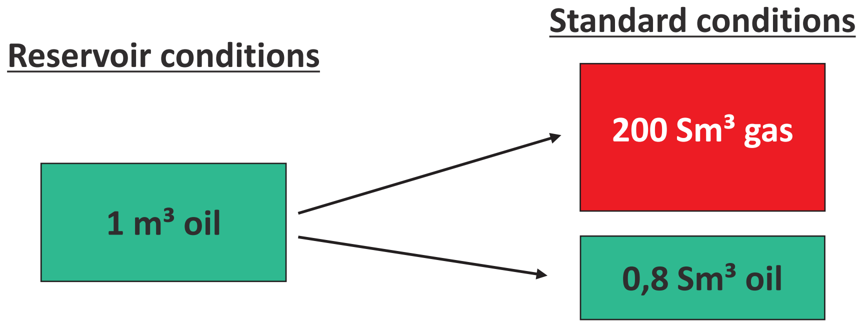
Condensate gas



- Retrograde gases have even fewer heavy molecules than volatile oils
- The critical point shifts to left and downward in the phase diagram and the critical temperature is usually less than reservoir temperature
- Retrograde condensate appears in the reservoir pore spaces at pressure below the dew point pressure. Throughout most of the reservoir, since the amount of liquid in the pore space is usually less than critical oil saturation the effective permeability to this condensate is zero and little is produced
- Along line 2 to 3, the condensate builds up at first and then revaporizes at the lower pressures
- This behavior is typical for constant composition expansion type application
- At reservoir conditions can we see re-evaporation?

4. Main oil and gas properties

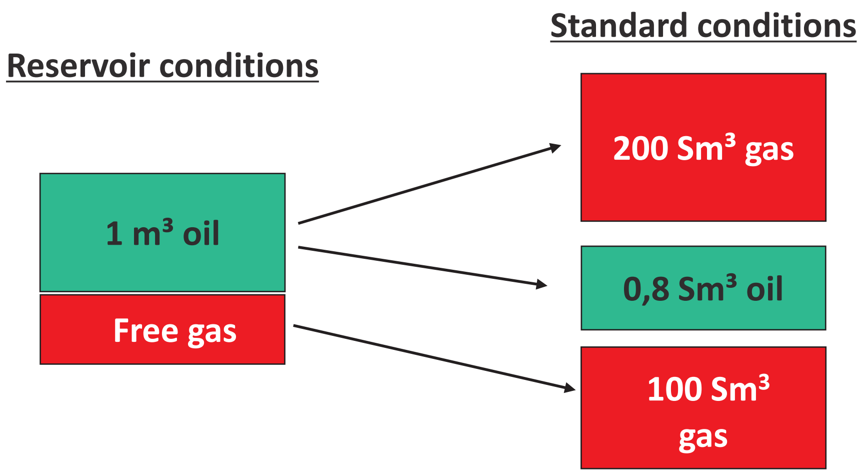
Oil properties – Solution GOR



Example:
Rs = 200/0.8 = 250 Sm3/Sm3

- **Solution GOR (Rs):**
  - Ratio between the volume of gas liberated at standard conditions and the volume of oil obtained at standard conditions
    Rs = Vg lib (Pstd,Tstd) / Voil (Pstd, Tstd)
  - Rs quantifies the amount of gaseous components which are dissolved in the reservoir oil.
  - Units: Sm^3/Sm^3, Scf/Stbbl
  - Typical values : 100 Sm^3/Sm^3 (black oil), 300 Sm^3/Sm^3 (light oil)

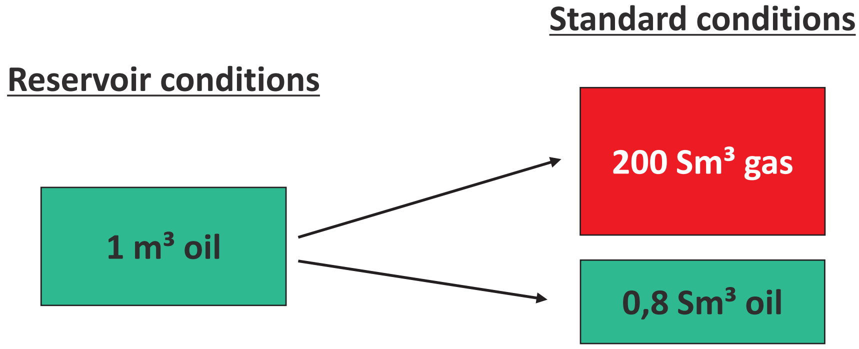
Oil properties – Production GOR



Example:
Production GOR = 300/0.8 = 375 Sm3/Sm3

- **Production GOR:**
  - Ratio between the volume of gas produced (liberated gas + free gas) at standard conditions and the volume of oil obtained at standard conditions
    GOR = (Vg lib (Pstd,Tstd) + Vg free (Pstd, Tstd)) / Voil (Pstd, Tstd)
  - Units: Sm^3/Sm^3, Scf/Stbbl
  - Production GOR ≥ Solution GOR

Oil properties – FVF



Example:
Bo = 1.0/0.8 = 1.25 v/v

- **Formation Volume Factor (FVF or Bo):**
  - Volume of oil at reservoir conditions (P,T) which must be produced to obtain 1 m^3 of oil at standard conditions
    Bo (P,T) = Voil (P, T) / Voil (Pstd, Tstd)
  - Units: v/v, m^3/Sm^3, bbl/Stbbl
  - Typical values: 1.25 v/v (black oil), 2.0 v/v (light oil)

$$Bo = \frac{\rho_g x R_s + \rho_{osT}}{\rho_{o(pT)}}$$

Oil properties – Compressibility and Viscosity

- **Isothermal Compressibility (Co)**
  - $Co = -\frac{1}{V}\left(\frac{\partial V}{\partial P}\right)_T = -\frac{1}{Bo}\left(\frac{\partial Bo}{\partial P}\right)_T$
  - Co quantifies the volume changes arising from pressure depletion at constant reservoir temperature, above the bubble point pressure

Units: 1/bar, 1/psi

Typical values: 1.10^{-4} bar^{-1} (black oil), 4.10^{-4} bar^{-1} (light oil)

- **Viscosity**
  - Viscosity increases with pressure (above Pb), and decreases with temperature and quantity of dissolved gas
  - Units: Poise
  - Typical values: 0,2 cP to 1 P (conventional oil), 1P to 100P (heavy oil)

Oil properties – Density

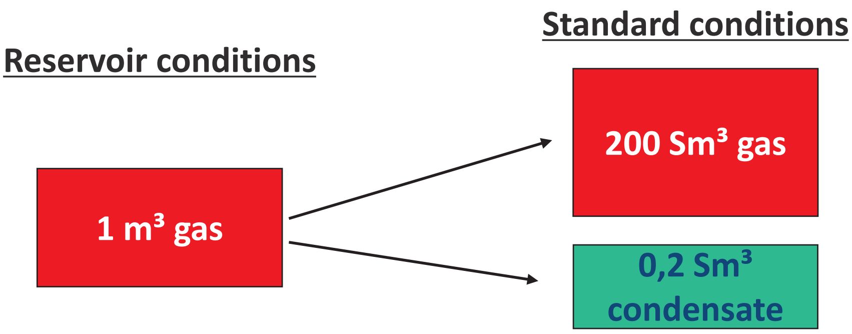
For stock tank oil (standard conditions), petroleum industry generally uses:

- **Specific Gravity (SG):**
  - The ratio of oil density to water density at standard conditions
    $SG = \rho_{oil} / \rho_{water}$
- **API Gravity:**
  - $°API = 141.5/SG - 131.5$
- **Oil density (ρ_{oil})**
  - In kg/m^3
  - Always less than 1000 kg/m^3

Condensate, very light oil: $SG \leq 0.8$ (more than 45°API)

Light oil	$0.8 \leq SG \leq 0.86$ (33 - 45°API)
Black oil	$0.86 \leq SG \leq 0.92$ (22 - 33°API)
Heavy oil	$0.92 \leq SG \leq 1$ (less than 22°API)

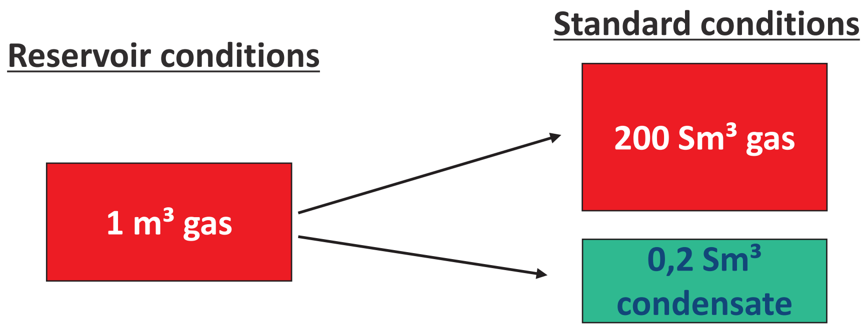
Gas properties – FVF



Example:
Bg = 1/200 = 0.005 v/v

- **Formation Volume Factor (FVF or Bg) for dry gas:**
  - Volume of free gas at reservoir conditions (P,T) which must be produced to obtain 1 m^3 of gas at standard conditions
    $Bg (P,T) = Vg (P, T) / Vg (Pstd, Tstd) \rightarrow Eg = 1/Bg$ (Expansion factor)
  - Units: v/v, m^3/Sm^3, cft/Stcft

Gas properties – CGR



Example:
CGR = 0.2/200 = 1000 Sm3/MSm3

- **Condensate to Gas Ratio (CGR):**
  - Ratio between the volume of liquid condensed (condensate) at standard conditions and the volume of gas obtained at standard conditions
    CGR = Vcond (Pstd,Tstd) / Vg (Pstd, Tstd) → GOR = 1 / CGR
  - Rs quantifies the amount of liquid components which are vaporized in the reservoir gas
  - Units: Sm^3/MSm^3, bbl/MMscf
  - Typical values : 50 bbl/MMscf (poor gas), 200 bbl/MMscf (rich gas)

Gas properties – Specific gravity and viscosity

Specific Gravity

- **Gas Specific Gravity is defined as the ratio of gas density to that of air at standard conditions (60°F, 1 atm):**
  - SG(air =1) = ρ_{gas}/ρ_{air}
    ρ_{air} = 28.97/23.645 = 1.225 kg/m³

Viscosity

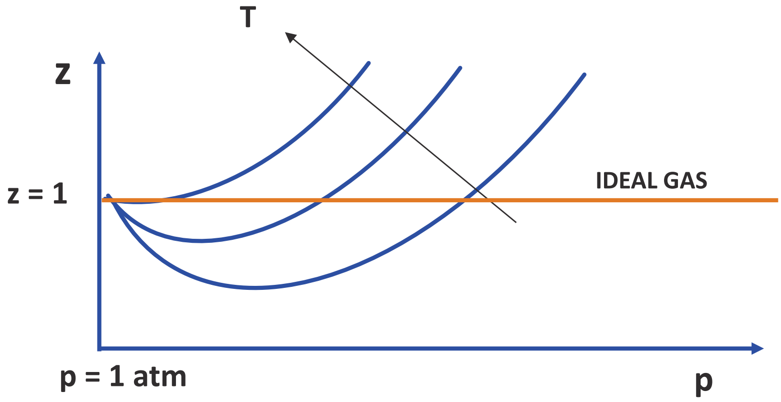
- **Viscosity varies with pressure, temperature, and molecular weight**
- **At low pressure, gas viscosity increases with temperature**
  At high pressure, gas viscosity decreases with temperature
- **It is often determined with correlations**
- **Units: Poise**
- **Typical values: 0.01 to 0.03 cP**

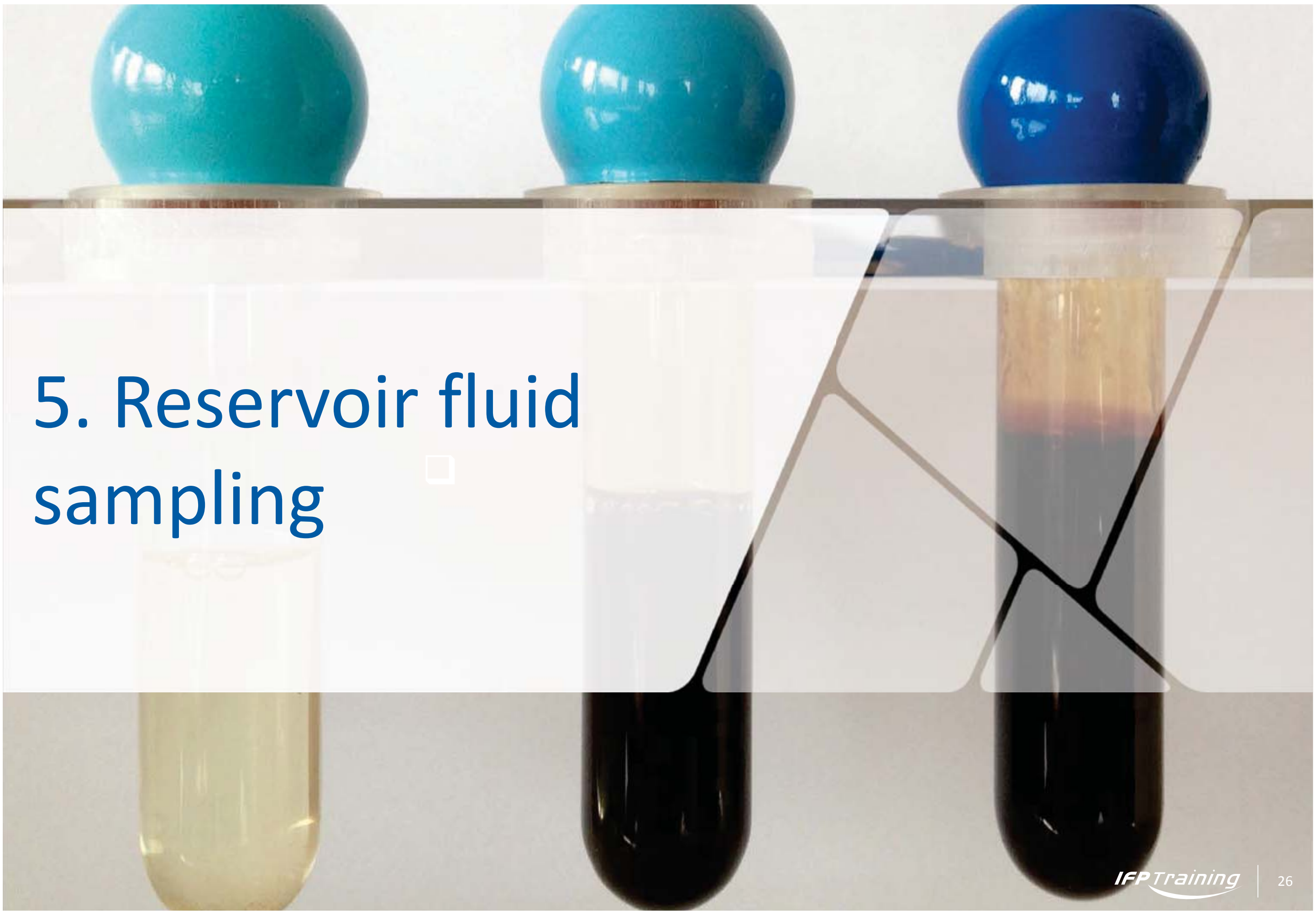
Gas properties – Compressibility factor

Compressibility factor: Z

- **For an ideal gas: PV = nRT**
- **For a real gas: PV = ZnRT**
  - Z depends on pressure, temperature, fluid composition
- **Gas FVF can be expressed as a function of Z:**
  Bg = Vg (P,T) / Vg (Psc, Tsc) = (Psc / P) . (T / Tsc) . Z

P = pressure
V = volume
n = number of moles
R = gas constant (R = 8.314 kJ/(kmol.K))
T = absolute temperature (K)
Z = compressibility factor, function of T and P





5. Reservoir fluid sampling

Reservoir fluids sampling

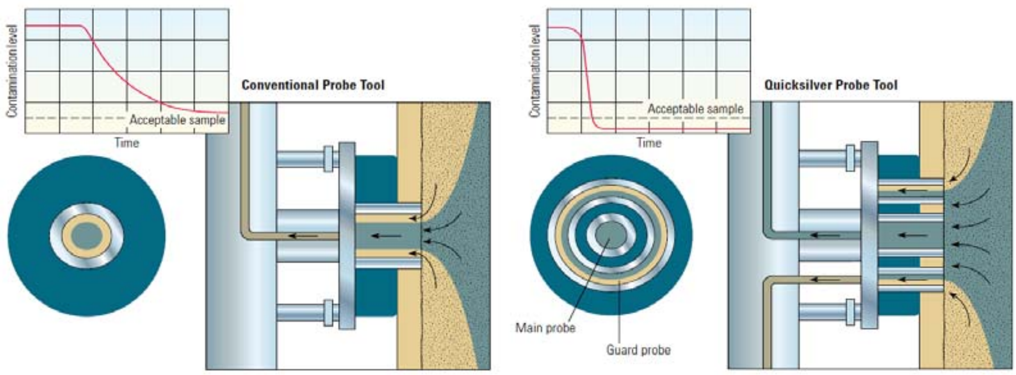
Objectives

- **The objective is to obtain a sample of fluid which is identical (representative) to the reservoir fluid**
- **Those samples are needed to:**
  - Determine the fluid type
  - Estimate **hydrocarbons in place** and **reserves**
  - Measure or estimate the fluid characteristics that will be used to design the production facilities or used in numerical models to predict reservoir performance

Reservoir fluids sampling

Bottom hole sampling

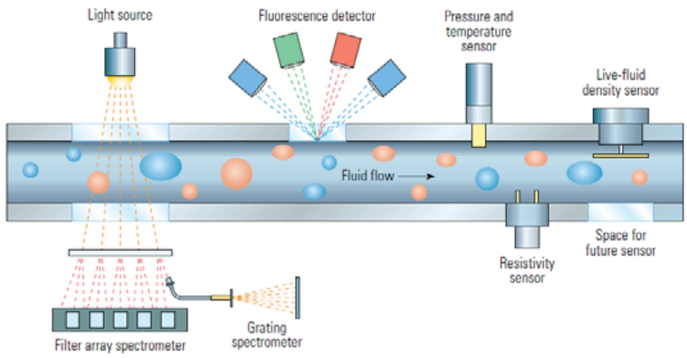
- **Fluid is collected at the bottom of the well in pressure and temperature, with a sampler**
- **Preferred since it guarantees the best fluid representativity**
- **Disadvantage:**
  - High cost
  - Possible contamination of sample by drilling fluids
- **Various tools are used: for example Modular Dynamic Formation Tester (MDT)**



Bottom hole sampling

In Situ Fluid Analyzer:

- Fluorescence sensors provide retrograde condensation detection and can differentiate oil type when the fluids are in emulsion
- pH of water is measured by injecting a pH-sensitive dye into the flow stream and detecting the color change
- P, T and resistivity sensors acquire data
- A live-fluid density sensor is located in the flow line



Reservoir fluids sampling
Surface sampling

- Oil and gas samples are collected from separator, at surface
- These samples are recombined in the laboratory, based on the measured gas/oil ratio, in order to make up a reservoir fluid as representative as possible
- The stability of the bottom hole and surface production parameters is very important in selecting the right moment for sampling
  - If the flowing pressure is lower than the saturation pressure (increasing GOR), on account of the difference in the mobility of the two phases in the porous medium, it will be difficult to get a fluid representative of the reservoir fluid (recombination with wrong proportions)
  - Fluid should be monophasic in order to have a good sampling

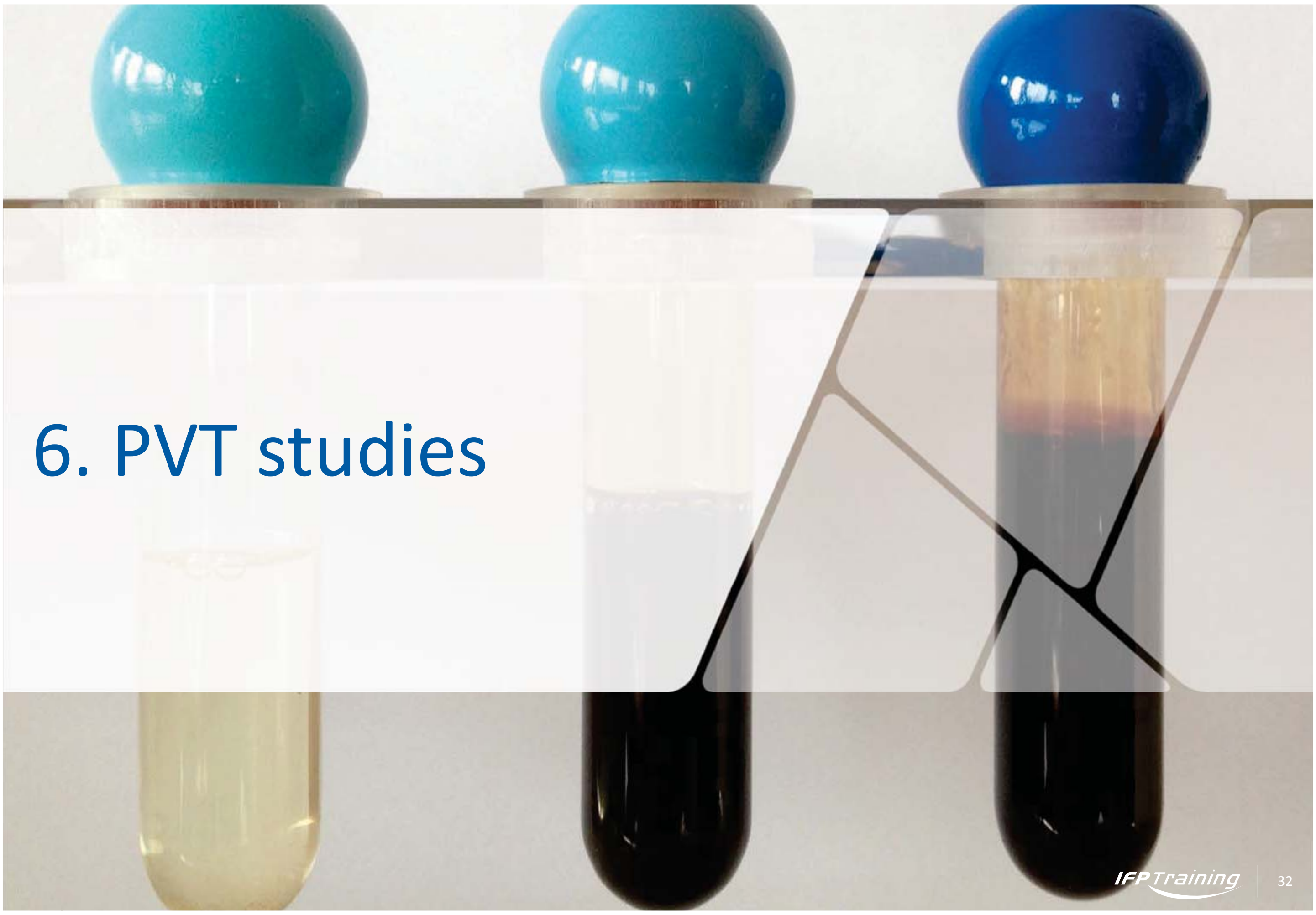
Reservoir fluids sampling

Gas condensate reservoir

- **Bottom hole sampling is not recommended for gas condensate or wet gas**
  - Low volume of fluid sampled gives low liquid recovery at laboratory and unrepresentative heavy components analysis
  - Possible segregation of the liquid at the well bottom
  - Liquid not totally recovered during transfer of bottom hole sample

- **Surface sampling**
  - Sample the well early in the field life
  - Produce the well with small drawdown to minimize formation of a condensate ring near the well bore
  - Stabilize the well rate above minimum gas velocity

- **Difficulties encountered during surface sampling of gas condensate**
  - Possible liquid carryover at the separator
  - Two different GOR can give the same dew point



6. PVT studies

Oil PVT study – Program

1. Quality control of samples

- Opening pressure (surface sampling)
- Saturation pressure (bottom or surface sample)

2. Compositional analysis

- Gas analysis: gas chromatography (C9)
- Oil analysis (atmospheric sample)
- Gas chromatography C11+ composition
- Distillation simulated by chromatography: C20+

3. Physical recombination (for surface samples)

- Field GOR correction

Oil PVT study – Program

4. Constant mass expansion

- P-V curve at reservoir temperature
  - bubble point pressure
  - relative volume
  - specific volume (calculated)
  - isothermal compressibility

5. Differential vaporization

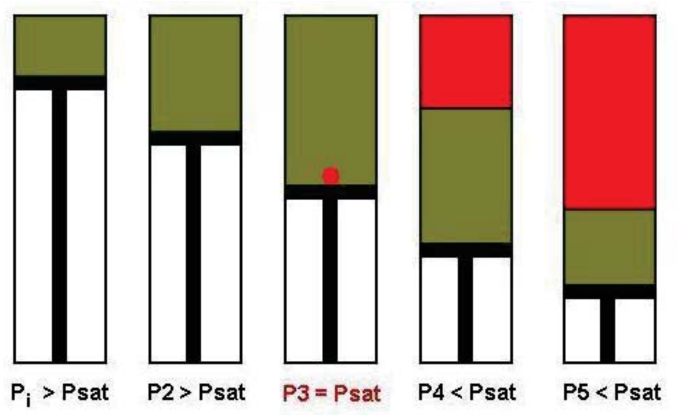
- Objective: simulate the initial liquid fraction remaining in the reservoir
- Realization: depletion and gas production at reservoir temperature by successive pressure drops
- Result: GOR cumulated, oil volume at each pressure step

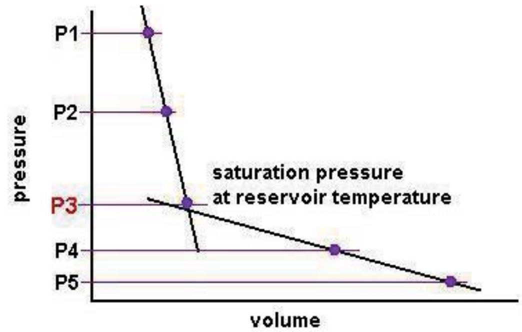
6. Flash separation

- Objective: obtain the highest recovery at stock tank conditions
- Realization: in one or several stages in a laboratory separator
- Result:
  - GOR
  - oil formation volume factor (Bo)
  - stock tank oil gravity
  - compositional analysis

Oil PVT Study – Constant composition expansion

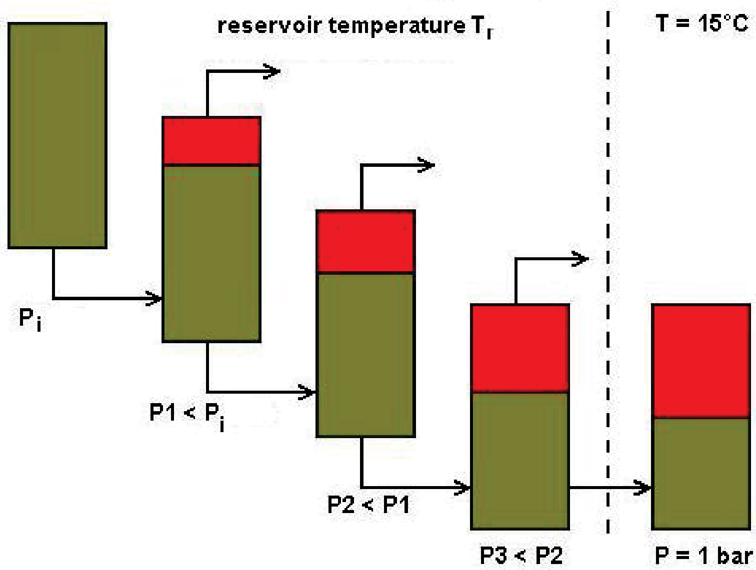
- **Determine:**
  - Bubble point pressure at reservoir temperature (Pb)
  - Isothermal compressibility factor of oil at bubble point (Co)
  - Gas compressibility factor (Z)
  - Global volume of oil as a function of pressure





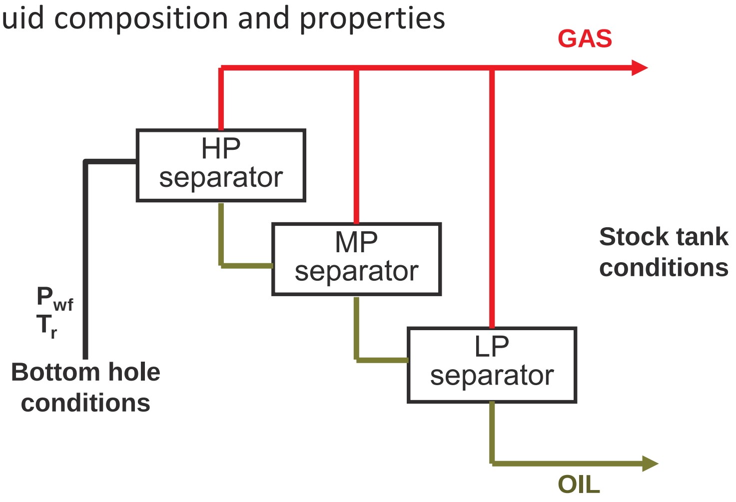
Oil PVT study – Differential vaporization

- **Determine:**
  - Bubble point pressure at reservoir temperature (Pb)
  - Amount of solution gas as a function of pressure
  - Liberated gas properties: compressibility, composition, density,Bg
  - Oil properties as a function of pressure: density, Bod, Bobd, Rsd,



Oil PVT study – Separator test

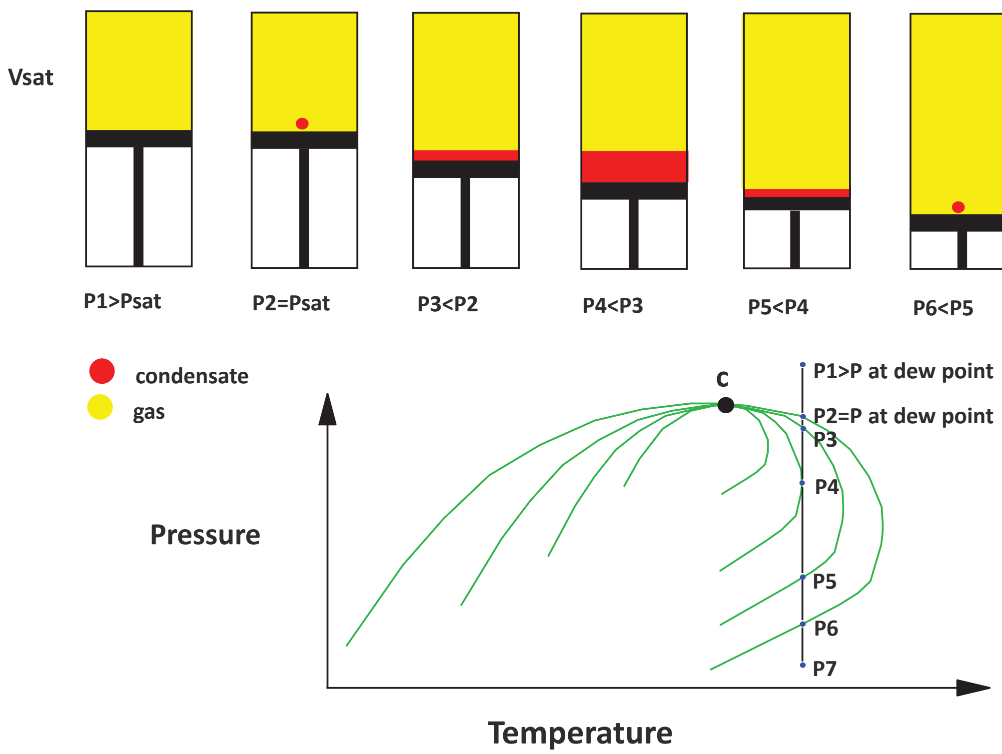
- **Objective**
  - Simulation of field test or process separation scheme
- **Main properties derived from this experiment**
  - GOR
  - Process R_{si}, Process B_{oi}
  - Gas composition at each step
  - Stock tank liquid composition and properties



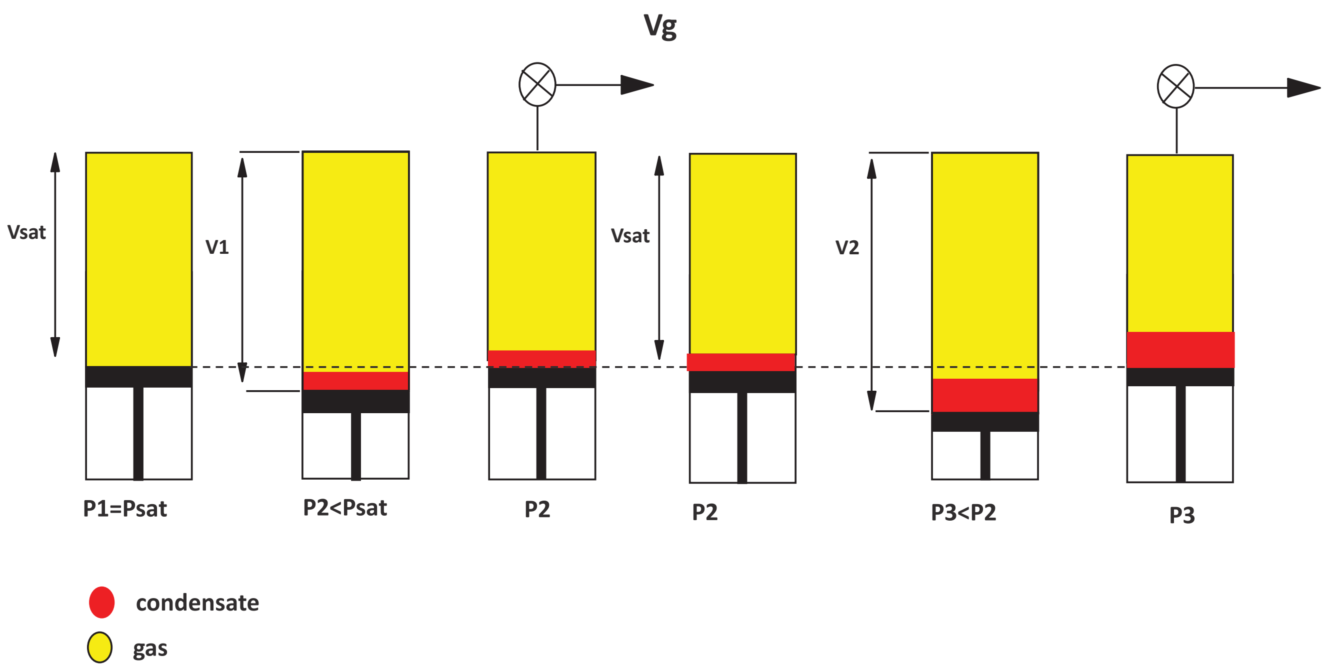
Gas PVT study – Program

1. **Quality control of samples**
   - Opening pressure, saturation pressure
2. **Compositional analysis**
   - Reservoir fluids composition up to C11+ or C20+
3. **Physical recombination**
   - Field GOR correction
4. **Constant Composition Expansion (CCE)**
   - P-V relation at reservoir temperature
   - Dew point, liquid condensation vs pressure
5. **Constant Volume Depletion (CVD)**
   - Reservoir simulation of depletion at constant volume and reservoir temperature
   - Pressure steps depletion:
     - liquid condensation
     - gas production and composition

Gas PVT study – Constant composition expansion



Gas PVT study – Constant volume depletion



Key points to keep in mind

Thermodynamics

- **Equilibrium**
  - Chemical species are characterized by equilibrium diagrams between their various phases
  - Different for pure components and mixture
- **Liquid-vapor equilibrium diagram (P,T)**
  - One curve for pure component ending at the critical point
  - One phase envelope for a mixture with two parts: the bubble point curve and the dew point curve connecting at the critical point
- **Saturation pressures**
  - Bubble point: pressure at which the first gas bubble appears
  - Dew point: pressure at which the first liquid droplet appears
- **Oil and gas definition**
  - Oil: a reservoir fluid showing a bubble point at reservoir temperature
  - Gas: a reservoir fluid showing a dew point at reservoir temperature

Key points to keep in mind

Petroleum fluids classification

- **Oil**
  - Oil system: critical temperature greater than reservoir temperature
  - Undersaturated oil: initial reservoir pressure above bubble point pressure @reservoir temperature → no free gas in the reservoir
  - Saturated oil: initial reservoir pressure equals to bubble point pressure @reservoir temperature → solution gas is released thus disturbing oil flow in the reservoir and increasing the GOR
- **Gas**
  - Gas system: critical temperature lesser than reservoir temperature
  - Dry gas: no liquid condensate neither in the reservoir nor in the surface
  - Wet gas: no liquid condensate in the reservoir but liquid condensate at the surface
  - Condensate gas: liquid condensate in the reservoir → can disturb gas flow and reduce production

Key points to keep in mind

Oil and gas properties

- **Oil:**
  - Formation volume factor (Bo)
  - Solution GOR (Rs)
  - Isothermal compressibility
  - Density
  - Viscosity
- **Gas:**
  - Formation volume factor (Bg)
  - Condensate to Gas Ratio (CGR)
  - Compressibility factor (Z)
  - Specific gravity
  - Viscosity

Key points to keep in mind

Reservoir fluids sampling

- **Two types of sampling**
  - Bottom hole sampling: Preferred but risks of getting the samples contaminated
  - Surface sampling: Easier but need to recombine fluids in laboratory to get a representative fluid (based on GOR)

PVT experiments in order to determine main fluid properties

- **Oil**
  - Constant mass expansion: bubble pressure, compressibility
  - Separator test: composition, viscosity, density, FVF and GOR
  - Differential vaporization: differential FVF and Rs, liberation GOR
- **Gas**
  - Constant composition expansion
  - Constant volume depletion: liquid drop-out curve, composition

Fundamentals of Reservoir Engineering – Well Testing and Well Test Analysis

Week#2

PTTEP Algeria

November 2016

IFP Training

Outline

1. **Introduction**
2. **Wellbore storage**
3. **Skin**
4. **Conventional analysis**
   - Horner method
5. **Derivative**
6. **Reservoir heterogeneities / boundaries**
7. **Gas well tests**

1. Introduction

Principle

- **Well test**
  - A well rate variation creating a disturbance in the pressure regime within the reservoir
  - Pressure at bottom of the well is recorded versus time

Variation of well rate (at surface) → **Well parameters + Reservoir properties** → **Pressure measurement versus time(at the bottom)**

- Evolution of bottom hole pressure versus time gives indication on well parameters and reservoir properties

Length Scale

Source: Vinson and Bissell (1992)

Objectives of a well test

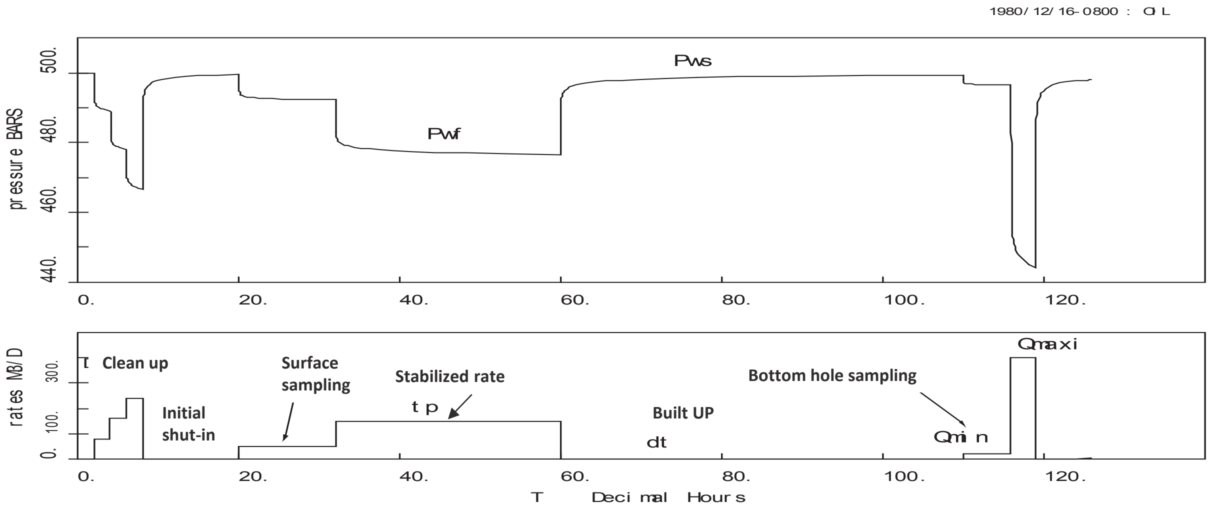
- **Why are wells tested?**
  - Confirm the presence of hydrocarbons
  - Measure initial reservoir pressure and temperature
  - Determine productivity
  - Determine permeability-thickness
  - Determine completion efficiency
  - Identify presence of nearby boundaries
  - Obtain fluid samples for analysis
  - Determine reservoir size

- **Or may be to do with the SEC**
  " … reserves are considered proved if the commercial productibility of the reservoir is supported by actual production or formation tests"

Typical well test

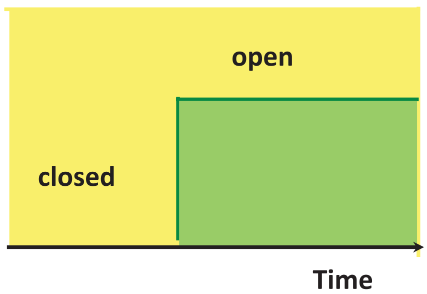
Test sequence example

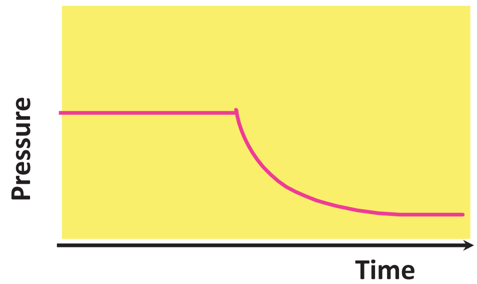
- Initial clean-up and shut-in
- Well production and GOR stabilization
- Surface sampling
- Stabilized rate
- Pressure build-up
- Bottom hole sampling
- Maximum well rate



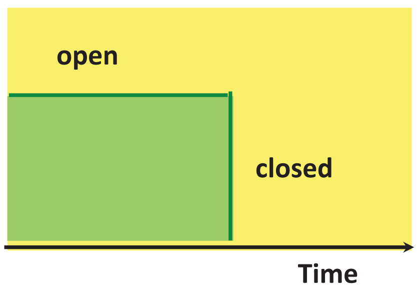
Pressure draw-down and build-up

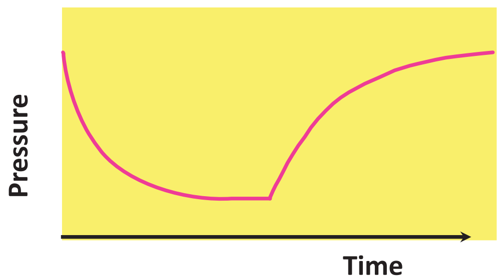
Producer





Draw Down

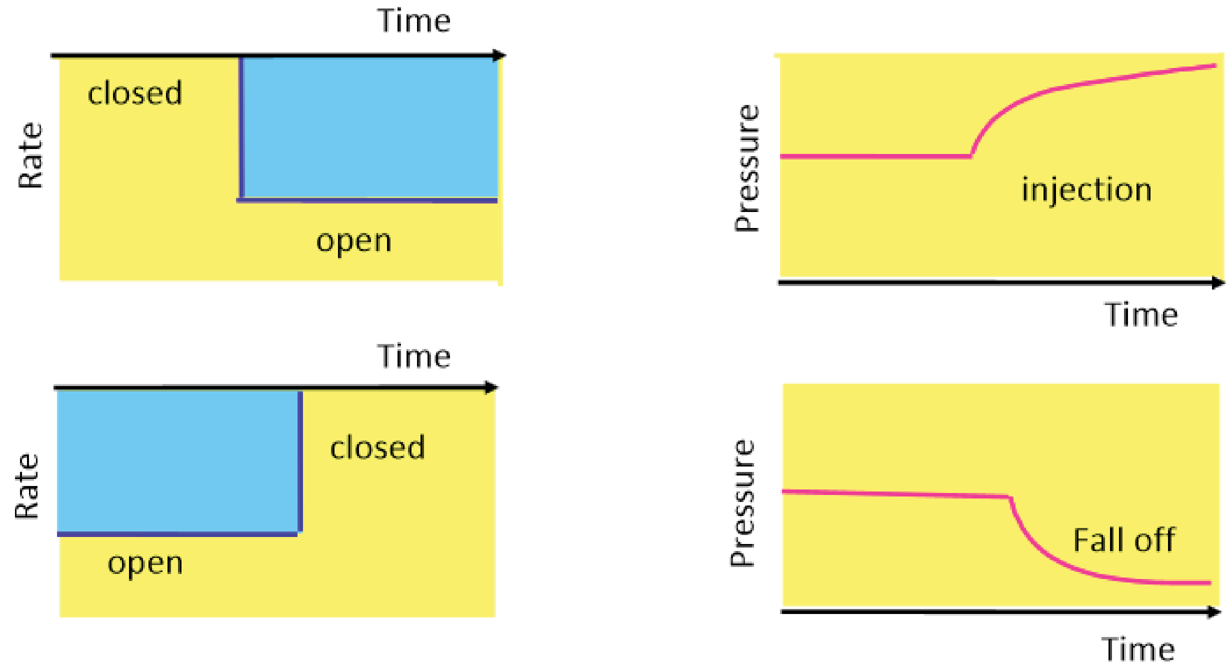




Build Up

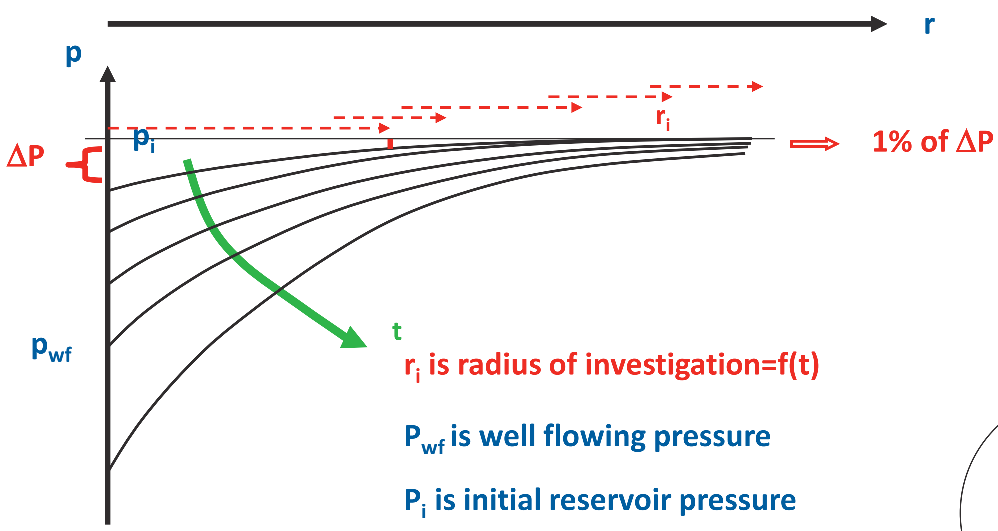
Pressure fall-off

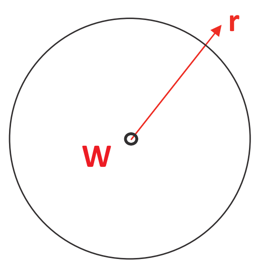
Injector



Pressure response

- Schematic example of pressure response in space and time during drawdown





Single and multiplace flow

- **Generally, two kinds of situations can occur in a reservoir**
  - Flow of only one fluid, either alone in the layer or in the presence of another immobile fluid (**single-phase flow**)
  - Two or three fluids move simultaneous (**multiphase flow**)

- **The laws of one-phase fluid mechanics**
  - Are relatively simple
  - Relate the flow rates and pressures in space, as a function of time, as well as of a number of rock and fluid properties

Typically, well tests are conducted to obtain information about a well or a reservoir

Fluid flow equation

- **Assumptions**
  - Constant temperature
  - Fluid compressibility small & constant
  - Fluid viscosity constant

- **Fluid flow in porous media is calculated applying the following principle**
  - Law of conservation of mass
  - Darcy's law
  - Equation of state

Fluid flow equation

- **Mass conservation law**

$$\frac{\delta}{\delta x}(\rho V_x)+\frac{\delta}{\delta y}(\rho V_y)+\frac{\delta}{\delta z}(\rho V_z)=\phi\frac{\delta\rho}{\delta t}$$

- **Darcy's law**

$$\vec{v}=\frac{k}{\mu}grad(P+\rho gz)$$

- **Equation of state (for oil)**

$$\rho=\rho_o e^{c(P-P_o)}\approx\ \rho=\rho_o\left[1+c_o(P-P_o)\right]$$

ρ: fluid density — ϕ: porosity — k: effective rock permeability

V: fluid velocity — c_o: oil compressibility — g: earth acceleration

Diffusivity equation

- **Combination of the three laws leads to the DIFFUSIVITY EQUATION**

- **Cartesian coordinates**

$$\frac{\delta^2 P}{\delta x^2}+\frac{\delta^2 P}{\delta y^2}+\frac{\delta^2 P}{\delta z^2}=\frac{\phi\mu_o c_o}{k}\frac{\delta P}{\delta t}$$

- **Radial coordinates**

$$\frac{\delta^2 P}{\delta r^2}+\frac{1}{r}\frac{\delta P}{\delta r}=\frac{\phi\mu_o c_o}{k}\frac{\delta P}{\delta t}$$

$\eta=\dfrac{k}{\phi\mu c}$ **is called the hydraulic diffusivity**

Solution to diffusivity equation

Infinite homogeneous reservoir

- **Pressure in the reservoir**

$$pi - p(r,t) = -\frac{qB\mu}{4\pi kh} Ei\left(\frac{-r^2}{4\eta t}\right) \text{, with } E_i(x) = \int_x^{\infty} \frac{e^{-u}}{u} du$$

- **If $\frac{r^2}{4\eta t}$ < 10^{-2}, then this expression can be approximated by the so called "logarithmic approximation"**

$$pi - p(r_w,t) = -\frac{q_o B_o \mu_o}{4\pi kh}\left(0.81 + Ln\frac{\eta t}{r_w^2}\right)$$

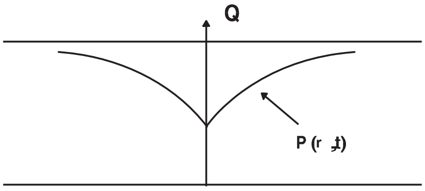
Flow regimes

Pressure Change Behavior = type of rate pressure change with respect to the elapsed time

can be of **3 different types**

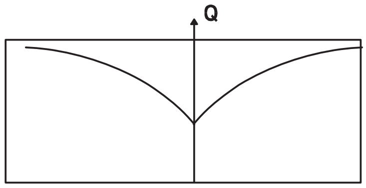
- **TRANSIENT STATE: pressure changes are governed by the well geometry and the reservoir characteristics.** $\frac{\partial p}{\partial t} = f(x,y,z,t)$
- **STEADY STATE: the pressure does not change with time (concept). The pressure are generated by a Steady State Flow, from constant pressure hypothesis, such as resulting from a strong water drive or a powerful gas cap. In real tests, pressure will always change, even slightly, with time.** $\frac{\partial p}{\partial t} = 0$
- **PSEUDO STEADY STATE: the pressure change is constant with time. Pressures are generated by a Pseudo Steady State Flow, such as resulting during pure Well Bore Storage or in a Closed Reservoir when all boundaries are reached.** $\frac{\partial p}{\partial t} = cte$

Flow regimes

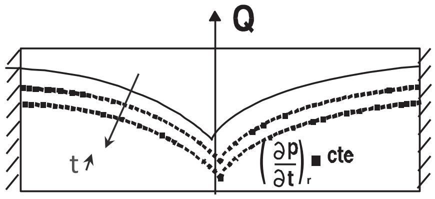


Transient: no limits affect the pressure profile around the well

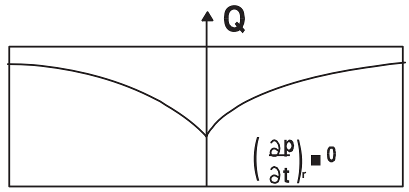
(infinite acting reservoir)



Late Transient: some limits have been reached



Peudo Steady State: all the limits have been reached -> during depletion the pressure profile follows the decrease in pressure



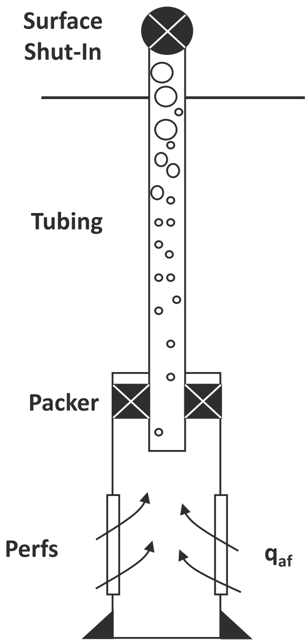
Steady State: same as Pss but limits show a cte pressure -> stabilized profile

2. Wellbore storage

Wellbore storage

Afterflow and Wellbore Storage(C)

Afterflow Calculation for Liquid-Filled Wellbore

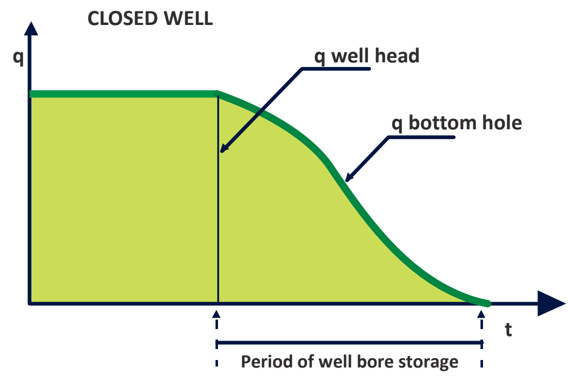


$$C = c_{wb} V_{wb} = -\frac{\Delta V}{\Delta P}$$

Where:

c_{wb} = average compressibility of fluids in wellbore, 1/psi

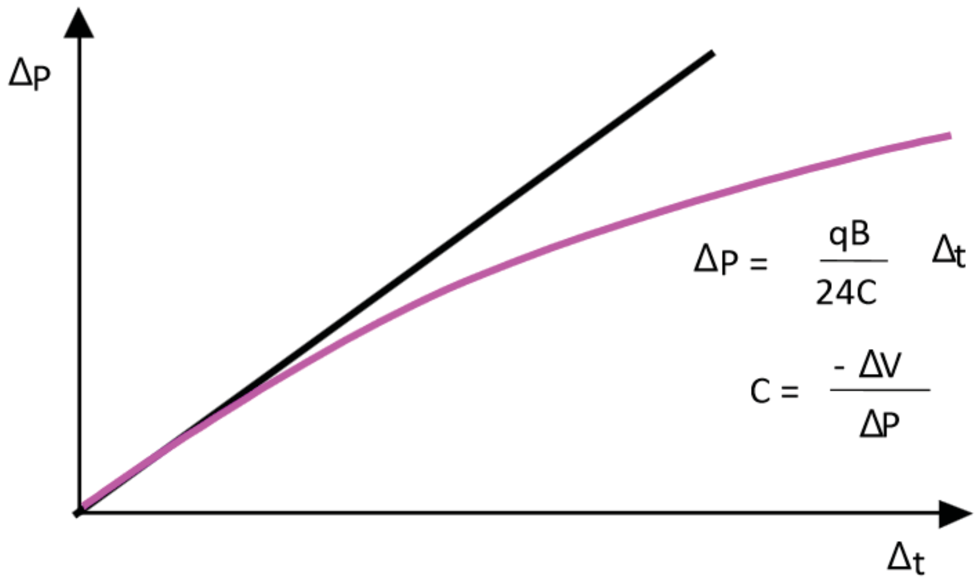
V_{wb} = wellbore volume, bbls



C reflects the compression or decompression of the fluid within the well following a rate change

Wellbore storage

During the period of well bore storage, bottom hole pressure is linear with time (if C constant)



Wellbore storage

Well with bottom hole closure	10^{-4} - 10^{-3} m^3/bar (4 10^{-5} - 4 10^{-4} bbl/psi)
Well with surface closure	10^{-2} - 10^{-1} m^3/bar (4 10^{-3} - 4 10^{-2} bbl/psi)
Pumping well	0.1 - 1 m^3/bar (4 10^{-2} - 4 10^{-1} bbl/psi)

3. Skin

Wellbore damage

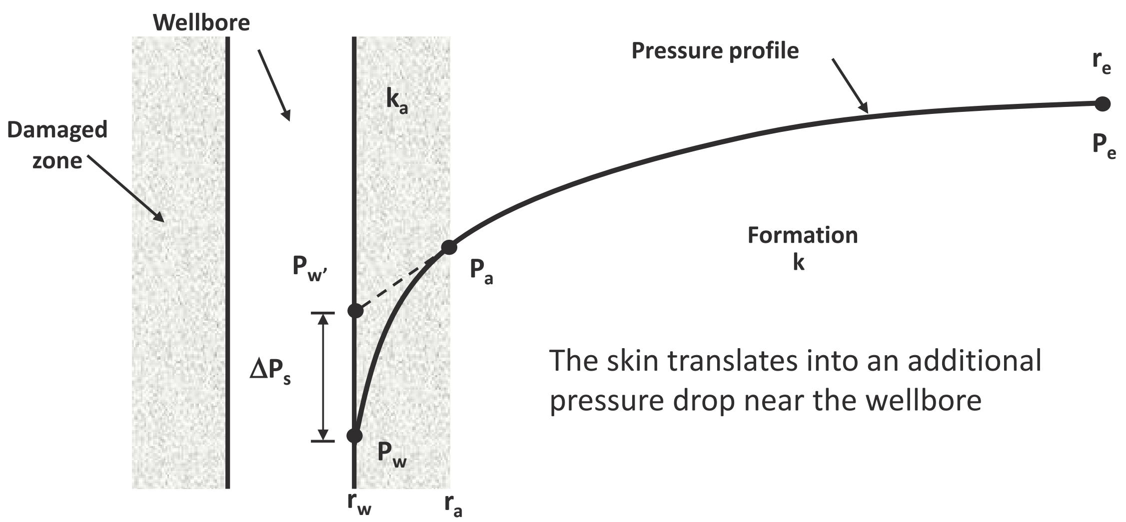
- **The skin S expresses the quality of the communication between the well and the reservoir**
- **This communication can be damaged by:**
  - drilling mud (cake, filtrate)
  - gas saturation (for an oil well)
  - poor quality perforations
  - scale formation …

Dammage → S > 0

- **This communication can be improved by:**
  - acid treatment
  - hydraulic fracturing
  - high angle wells

Stimulation → S < 0

The Skin factor in practice…



The skin translates into an additional pressure drop near the wellbore

$$S = S_m + S_g + S_q$$

Total skin

Mechanical skin: the part of the skin we can act on

Geometric skin: estimated with models

Turbulent skin: estimated with well tests

4. Conventional analysis

Horner plot

Horner method

The Horner analysis

- **The Horner analysis is done on pressure build-up data. The production history of the well consists in two phases:**
  - First a pressure draw down phase, corresponding to a constant rate production
  - Then a pressure build-up phase corresponding to a zero production rate

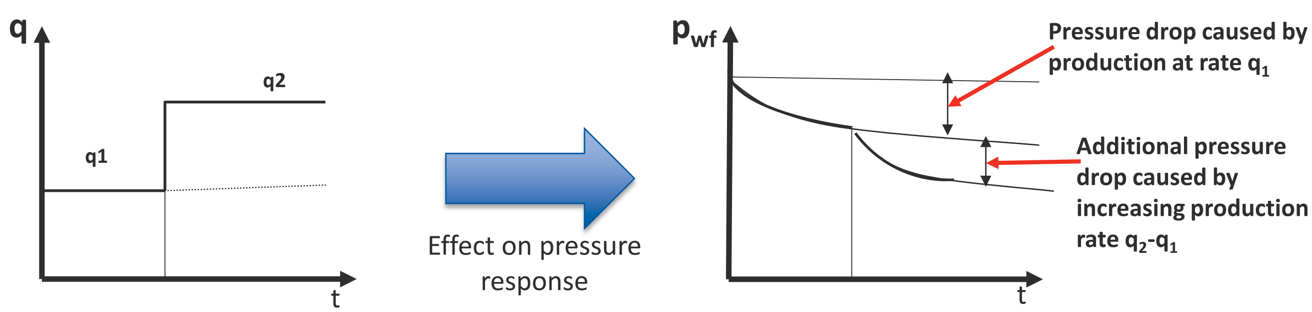
- **The superposition principle is then applied to derive the Horner equation**

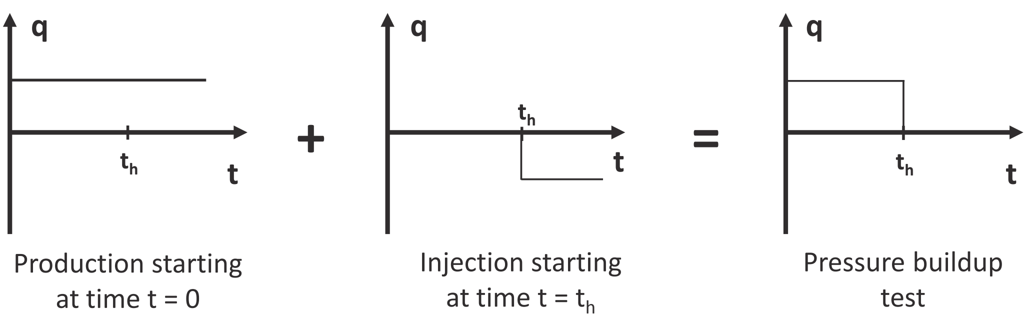
- **The major interest of this method resides in the fact that it is much easier to produce a zero rate (Q=0) than a controlled constant rate Q**

Principle of superposition

- **Principle of superposition: the response of the system to a number of perturbations is exactly equal to the sum of the responses of each perturbation taken independently**
- **This is true if the system is linear, e.g. it would not apply if there was hysterisis**
- **This principle applies in space and time**

Principle of superposition





$$Pi - Pws(\Delta t) = [Pi - Pwf(t_h + \Delta t)] - [Pi - Pwf(\Delta t)]$$

Derivation of Horner equation using principle of superposition

- **Production starting at time t = 0:** $(p_i - p_w)_q = \dfrac{141.2\, q\mu B}{kh}\left[\dfrac{1}{2}\left(\ln\left(\dfrac{\eta t}{r_w^{\,2}}\right) + 0.809\right)\right]$ (1)

- **Injection starting at time t = th:** $(p_i - p_w)_{-q} = \dfrac{141.2\,(-q)\mu B}{kh}\left[\dfrac{1}{2}\left(\ln\left(\dfrac{\eta(t - t_h)}{r_w^{\,2}}\right) + 0.809\right)\right]$ (2)

- **Add (1) + (2) to obtain Horner equation:**

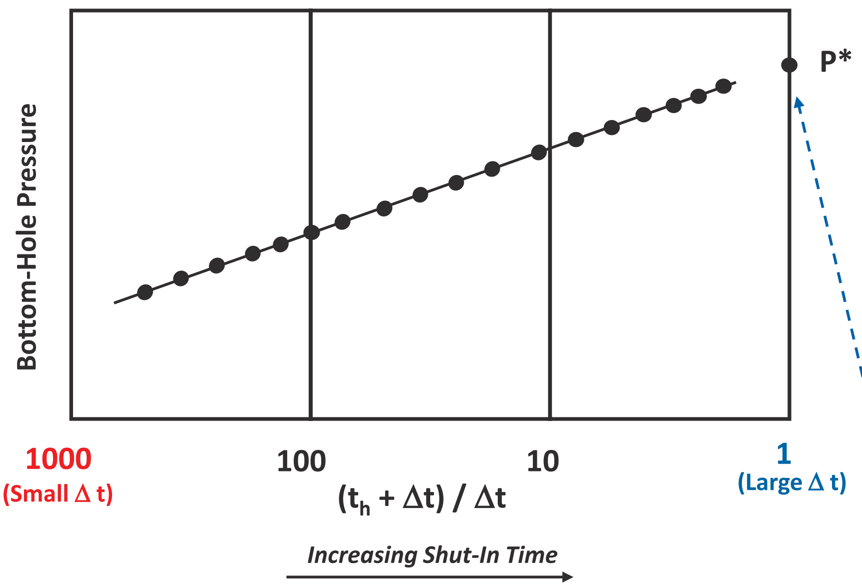
$$p_{ws} = p_i - \frac{162.6\, q\mu B}{kh}\log\left[\frac{t_h + \Delta t}{\Delta t}\right] \qquad (3)$$

Pws:	Shut-in bottom-hole pressure (psi)
Pi:	Initial reservoir pressure (psi)
q :	Flow rate (stb/d)
B :	Formation volume factor (rb/stb)
µ :	Viscosity (cP)
k :	Formation permeability (mD)
h :	Formation thickness (ft)
t_h :	Horner time (minutes)
$\Delta t = t - t_h$, time since shut-in (minutes)	

Horner analysis

Plotting P_{ws} vs log $((t_h+\Delta t)/\Delta t)$ yields a straight line

The slope of that straight line is proportional to (kh/µ)



Infinite
Shut-In Time
$(t_h + \Delta t) / \Delta t = 1$
$\Delta t \rightarrow$ infinity

Assumptions

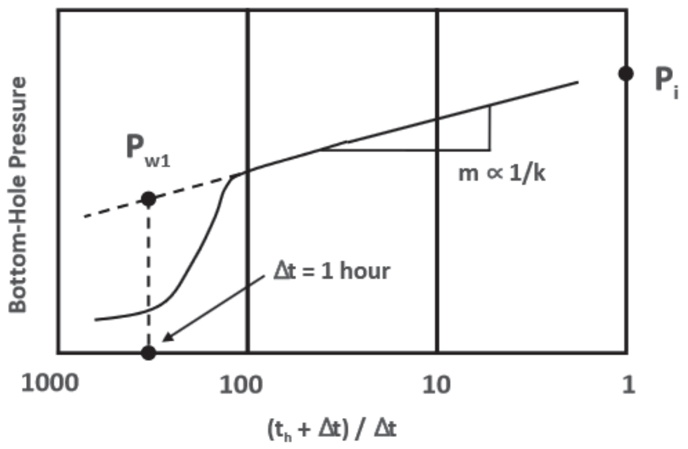
- Infinite reservoir
- Homogeneous reservoir
- Radial flow
- Constant fluid properties
- Slightly compressible fluid
- Darcy's Law
- Instantaneous shut-in

Permeability and Skin factor

$$k = \frac{C\ Bo\ q\ \mu}{m\ h}$$

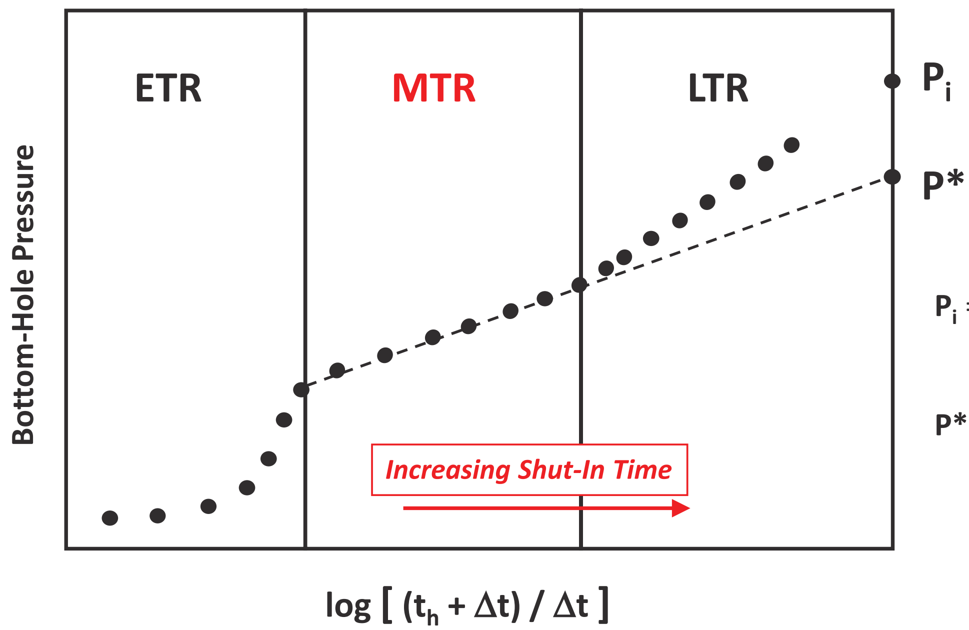
C = 0,183 SI units
C = 21,907 Practical metric units
C = 162,59 Oilfield units

$$S = 1.151\left\{\frac{P_{w1} - P_{wf}}{m} - log\left[\frac{k}{\varphi\mu c_t rw^2}\right] + 3.23\right\}$$



Horner plot regions

The straight line, when existing, is restricted to the **M**iddle **T**ime **R**egion



P_i = Initial Reservoir Pressure

P* = Extrapolation of MTR to infinite shut-in time

Early-Time Region (**ETR**): Wellbore phenomena (afterflow) and Near-wellbore phenomena (damage)
Middle-Time Region (**MTR**): Representative of formation properties
Late-Time Region (**LTR**): Reservoir heterogeneities (boundaries)

5. Derivative

Derivative method

- The derivative analysis was introduced in the 1980s by D. Bourdet and it is based on fact that the change in pressure is more meaningful than the pressure itself, the introduction of the derivative method has brought a significant improvement to the log-log analysis

- Proper handling of multirate tests / production

- Numerous Well and Reservoir models available

- Excellent tool for identification of flow regimes and reservoir models

- But sometimes, the differentiation of pressure data leads to significant noise

Derivative method

- It is defined as $$P_D' = \frac{dP_D}{dLn\frac{t_D}{c_D}} = \frac{t_D}{c_D} * \frac{dP_D}{d\frac{t_D}{c_D}}$$ $$(\Delta P)' = d\Delta P / dLn\left[\frac{t_h + \Delta t}{\Delta t}\right]$$

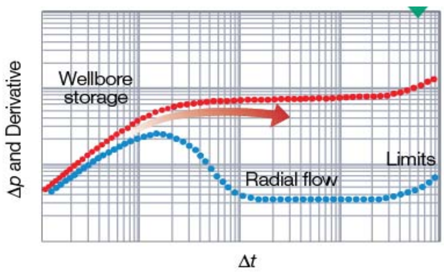
- The dimensionless parameters are defined as:

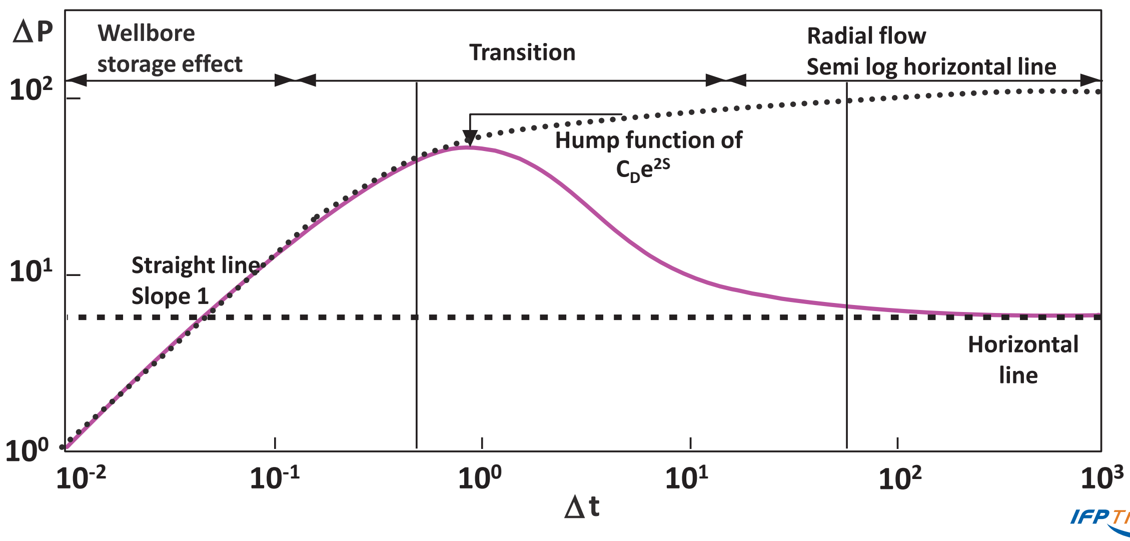
$$P_D = \frac{k\,h}{141.2\,q\,B\,\mu}\Delta P$$

$$t_D = \frac{0.000264\,k}{\phi\,\mu\,c_t\,rw^2}\Delta t$$

$$C_D = \frac{0.89\,C}{\phi\,c_t\,h\,rw^2}\Delta t$$

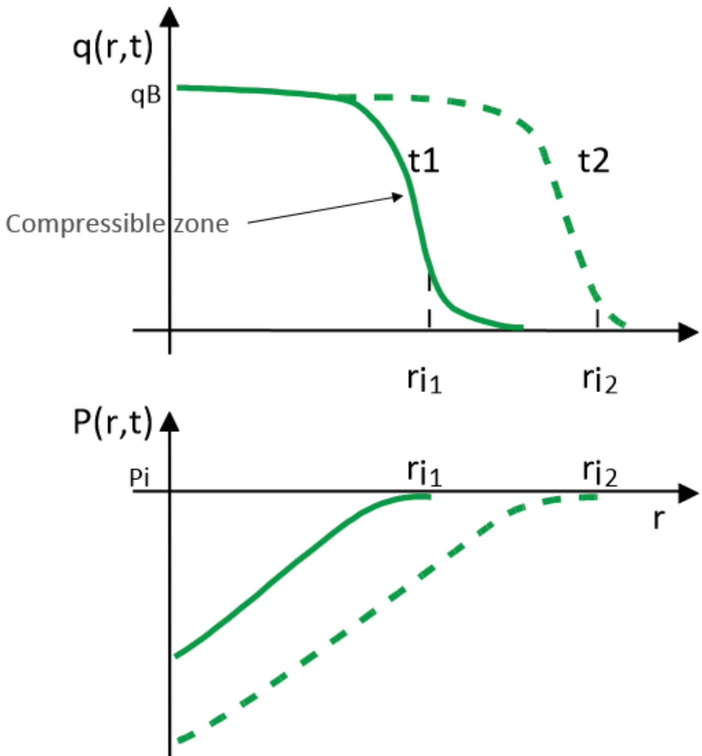
Derivative plot





6. Reservoir heterogeneities / Boundaries

Radius of investigation



$$q = q\,B\,e^{-\frac{r^2}{4\,k\,t}}$$

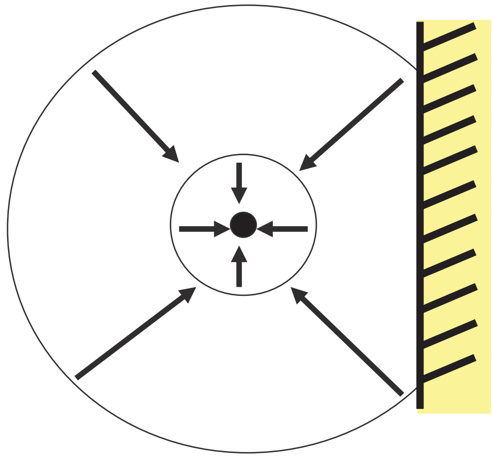
$$\frac{\partial^2 P}{\partial t^2} = 0 \;@\; \frac{r^2}{4\eta t}=1$$

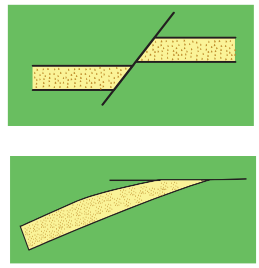
$$r_i = 0.032\sqrt{\frac{k\,t}{\phi\,\mu\,c_t}}$$

Radius of investigation

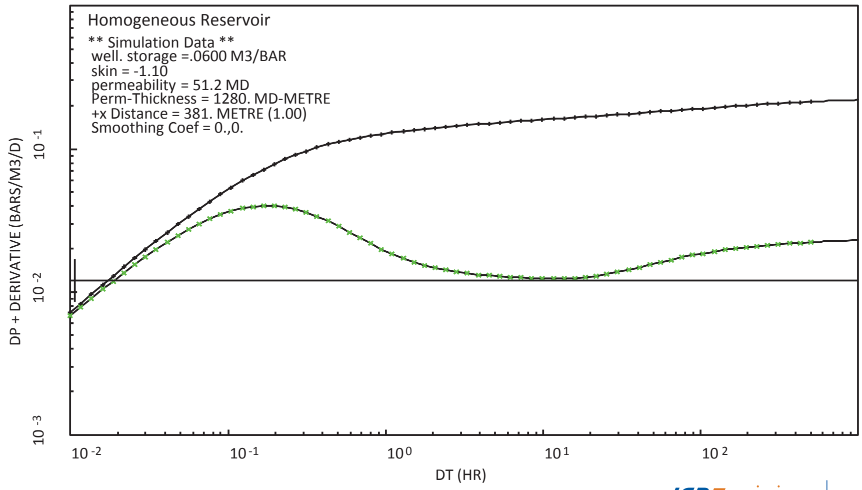
At time t, pressure evolution at bottom hole is function of the reservoir properties within the compressible zone

Sealing fault

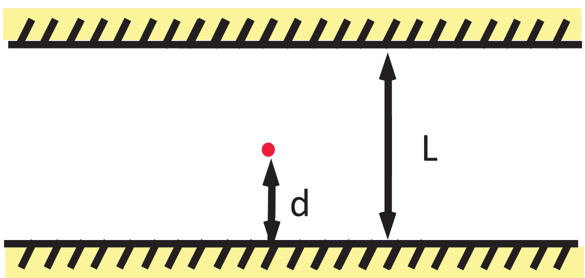


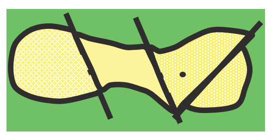


1. **Radial flow**
2. **Hemi-radial flow**

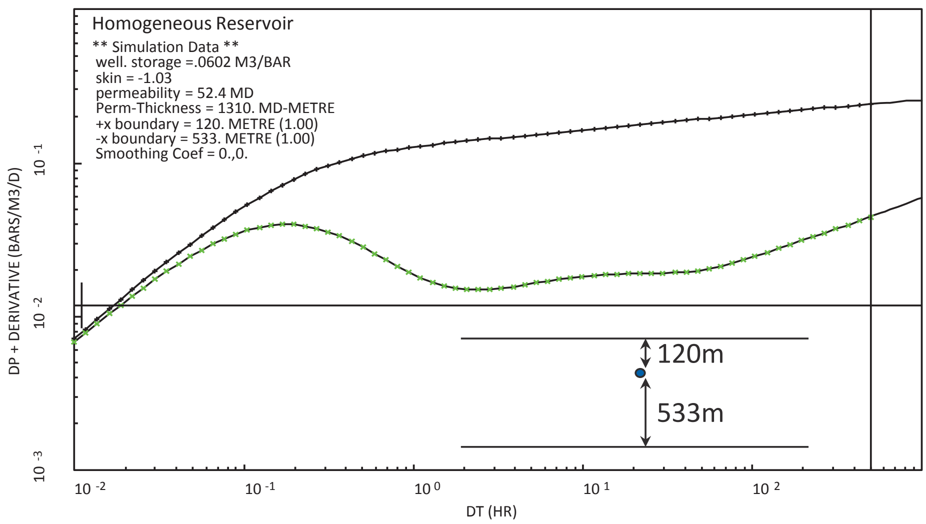


Channels





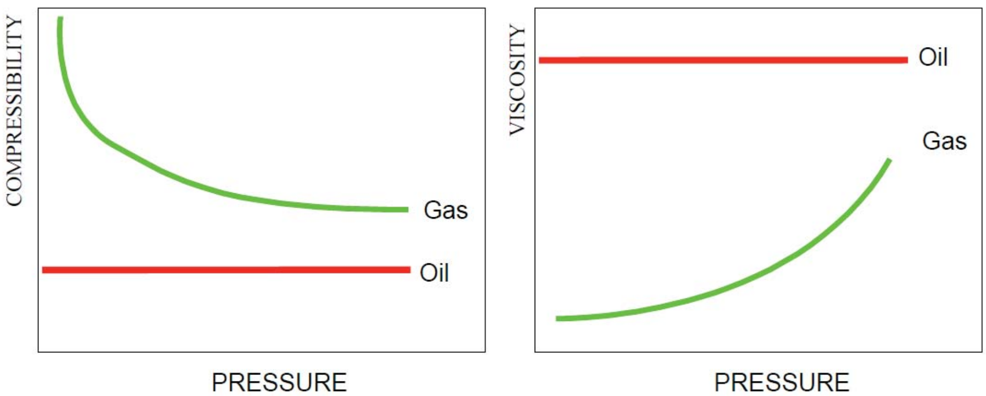
1. **Radial flow**
2. **Linear flow: when both infinite limits are reached**



7. Gas well tests

Gas versus oil

- **The diffusivity equation, derived to analyze oil wells, considers:**
  - low and constant compressibility
  - constant viscosity
  - low pressure gradient in the reservoir
- **In a gas well, the viscosity and compressibility vary with pressure**



Gas versus oil

- **However, as per the oil, the diffusivity equation governing the gas pressure behavior is also established from:**
  - *The Darcy law*, which applies in all the reservoir except in the near well vicinity (gas velocity is high and induces an additional pressure drop → *Non Darcy Skin*)

$$\vec{V} = -\frac{k}{\mu}\,\overrightarrow{\text{grad}}\,P \quad \text{(except at well)}$$

  - *The material balance*

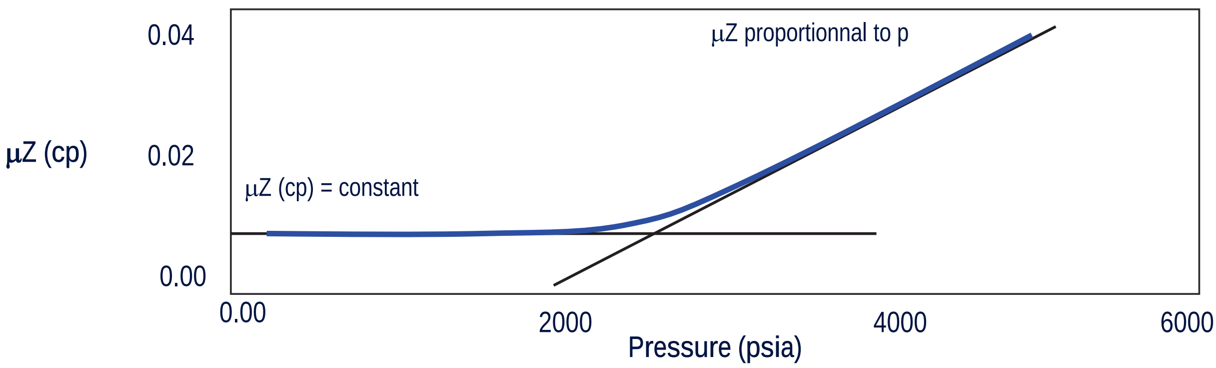
$$div\left(\rho \vec{V}\right) + \frac{\partial\left(\rho \phi S_h\right)}{\partial t} = 0$$

  - *The equation of state*, which defines the gas equivalent compressibility

(oil) $$C_o = \frac{1}{\rho}\left(\frac{\partial \rho}{\partial P}\right) \qquad \rho = \rho_o e^{C_o (P - P_o)}$$

(gas) $$C_g = \frac{1}{\rho}\left(\frac{\partial \rho}{\partial P}\right)_T \qquad \rho = \frac{PM}{ZRT} \qquad C_g = \frac{1}{P} - \frac{1}{Z}\left(\frac{\partial Z}{\partial P}\right)_T$$

Gas: The μZ versus pressure curve



In order to:

- **take into account the change of gas compressibility and viscosity with pressure and temperature, and**
- **allow the use of the oil diffusivity equation,**

the pressure variables are changed into « pseudo pressure m(P) »

The pseudo pressure m(P)

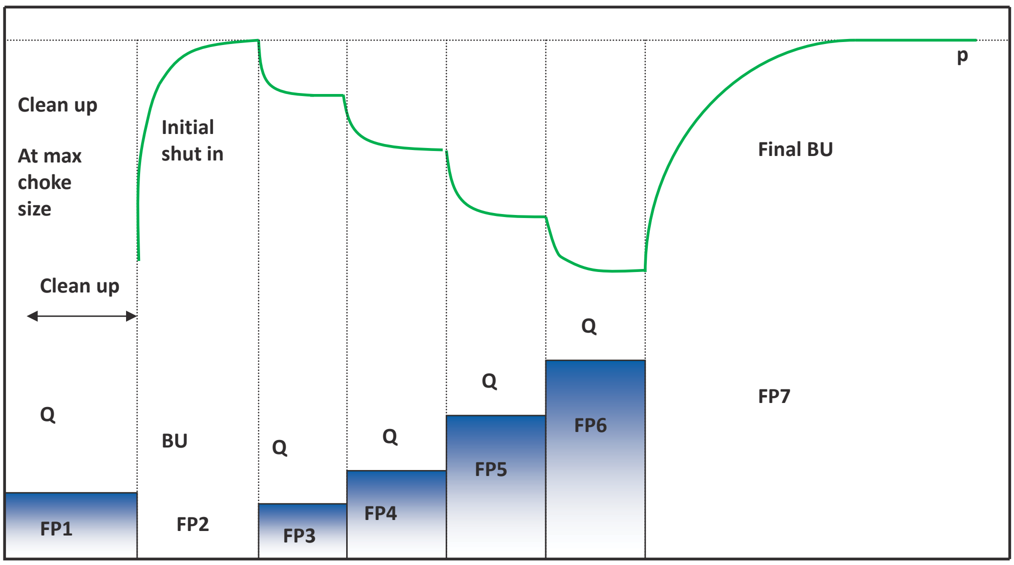
DIFFERENCE BETWEEN ANALYSING OIL AND GAS PRESSURE DATA

- **Oil is slightly compressible, when gas properties are highly pressure dependent (Viscosity μ and Compressibility C),**
- **To use the same equations developed for Oil Wells, the Real Gas Pseudo Functions, m(p), are introduced. The real gas pseudo-pressure function takes into account the variation in gas properties. It keeps the gas equations linear (as for oil) and analysis is carried on using Pseudo Pressure (m)p's instead of pressures…**

$$m(p) = \int_{p0}^{p} \frac{2p.dp}{\mu(p).Z(p)}$$

Gas well test

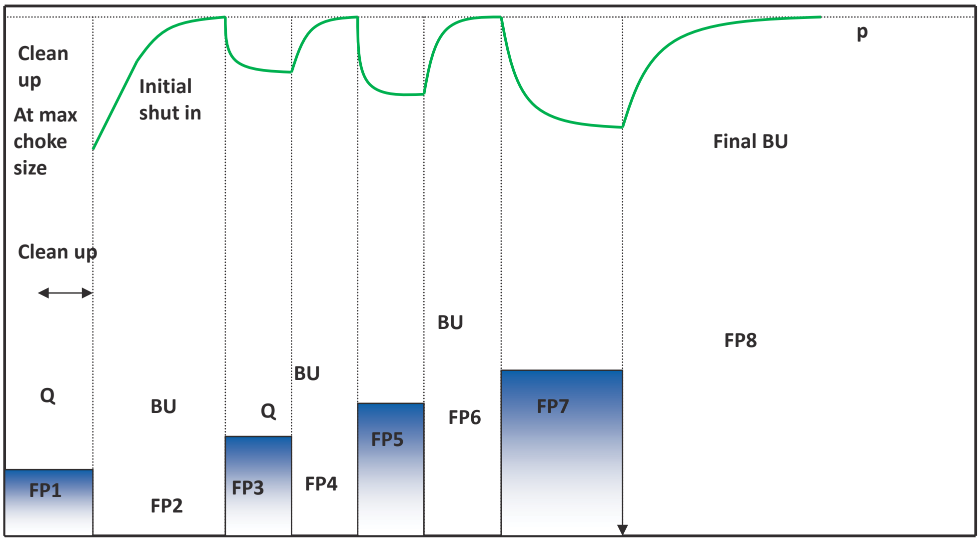
For high potential gas wells



Flow after flow gas test (or back pressure test)

Gas well test

For low productivity gas wells



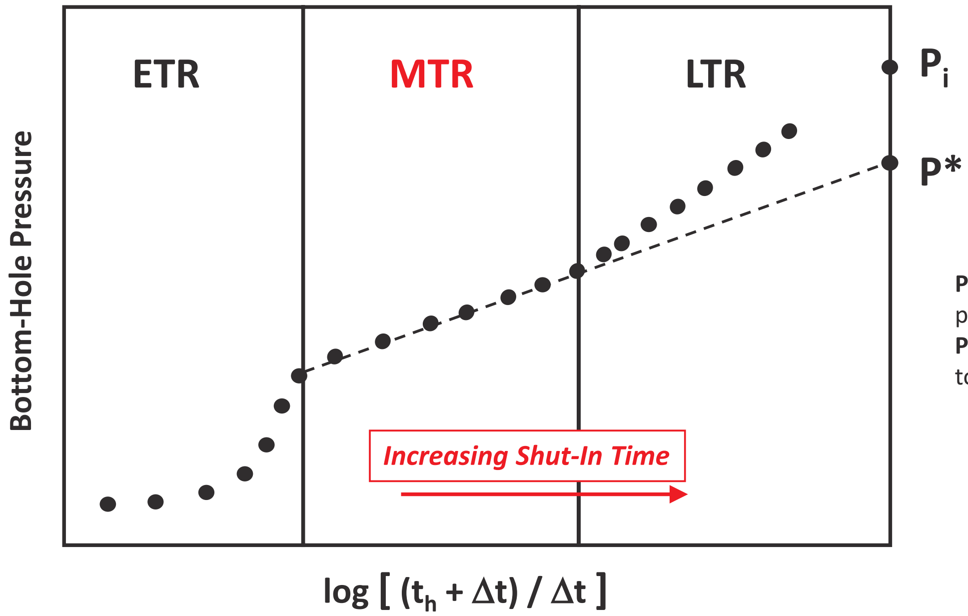
Isochronal Gas Test

Key points

- **Well test**
  - A well rate variation creating a disturbance in the pressure regime within the reservoir
  - Pressure at bottom of the well is recorded versus time
  - Evolution of bottom hole pressure versus time gives indication on well parameters and reservoir properties
- **Why are wells tested?**
  - Confirm the presence of hydrocarbons
  - Measure initial reservoir pressure and temperature
  - Determine productivity
  - Determine permeability-thickness
  - Determine completion efficiency
  - Identify presence of nearby boundaries
  - Obtain fluid samples for analysis
  - Determine reservoir size

Key points

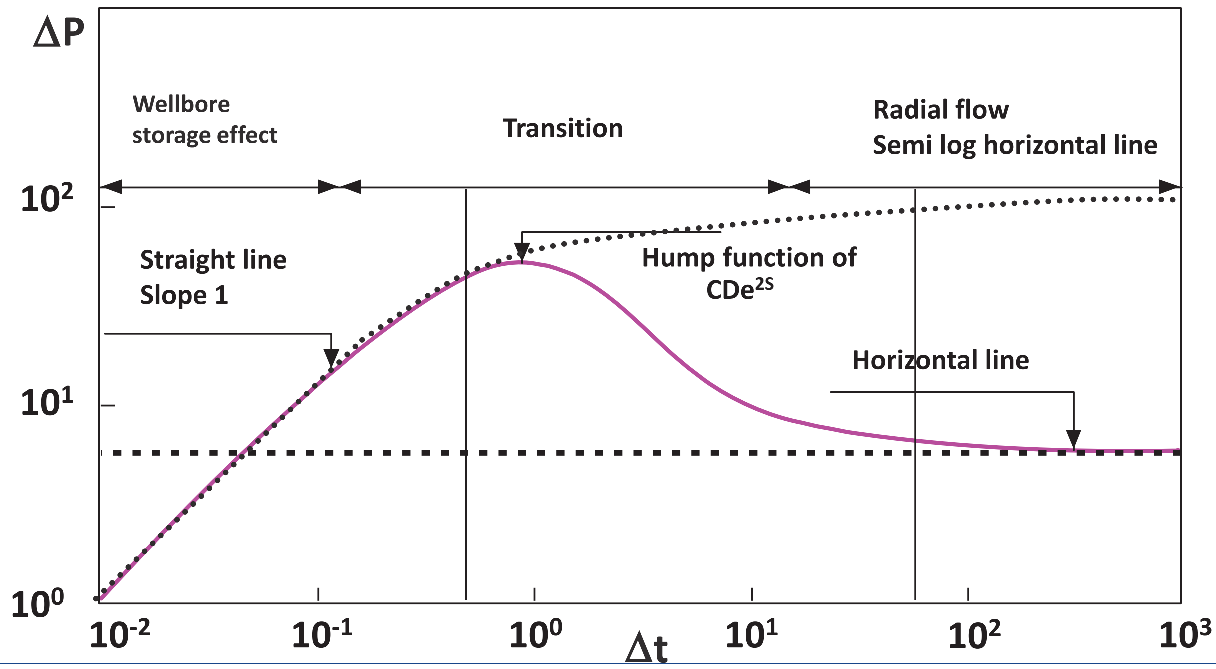
- Horner analysis



P_i = Initial reservoir pressure
P* = Extrapolation of MTR to infinite shut-in time

Key points

- Derivative analysis



Fundamentals of Reservoir Engineering – Drive mechanisms Primary recovery

Week#2

PTTEP Algeria

November 2016

Outline

1. **Introduction**
2. **Material Balance**
   a. Principles
   b. Undersaturated oil reservoirs
   c. Solution gas drive
   d. Gas cap drive
   e. Compaction drive
   f. Water drive
   g. Gas fields
3. **Generalized Material Balance Equation**
4. **Summary – key points**

1. Introduction

Reservoir engineering

FIELD DESCRIPTION:
- Data interpretation
- Original hydrocarbons in place evaluation

FIELD UNDERSTANDING:
- Production mechanisms
- Recoverable reserves

FIELD DEVELOPMENT STRATEGY:
- Data synthesis and integration
- Reservoir simulation model

Introduction

CONVENTIONAL OIL RECOVERY

PRIMARY RECOVERY: the field is produced thanks to its own energy

- NATURAL DRAINAGE
- LIFT / HORIZONTAL DRILLING

SECONDARY RECOVERY: energy is provided to the field through injection

- WATER INJECTION
- GAS INJECTION
- GAS CYCLING

- PRESSURE MAINTENANCE
- SWEEP EFFICIENCY

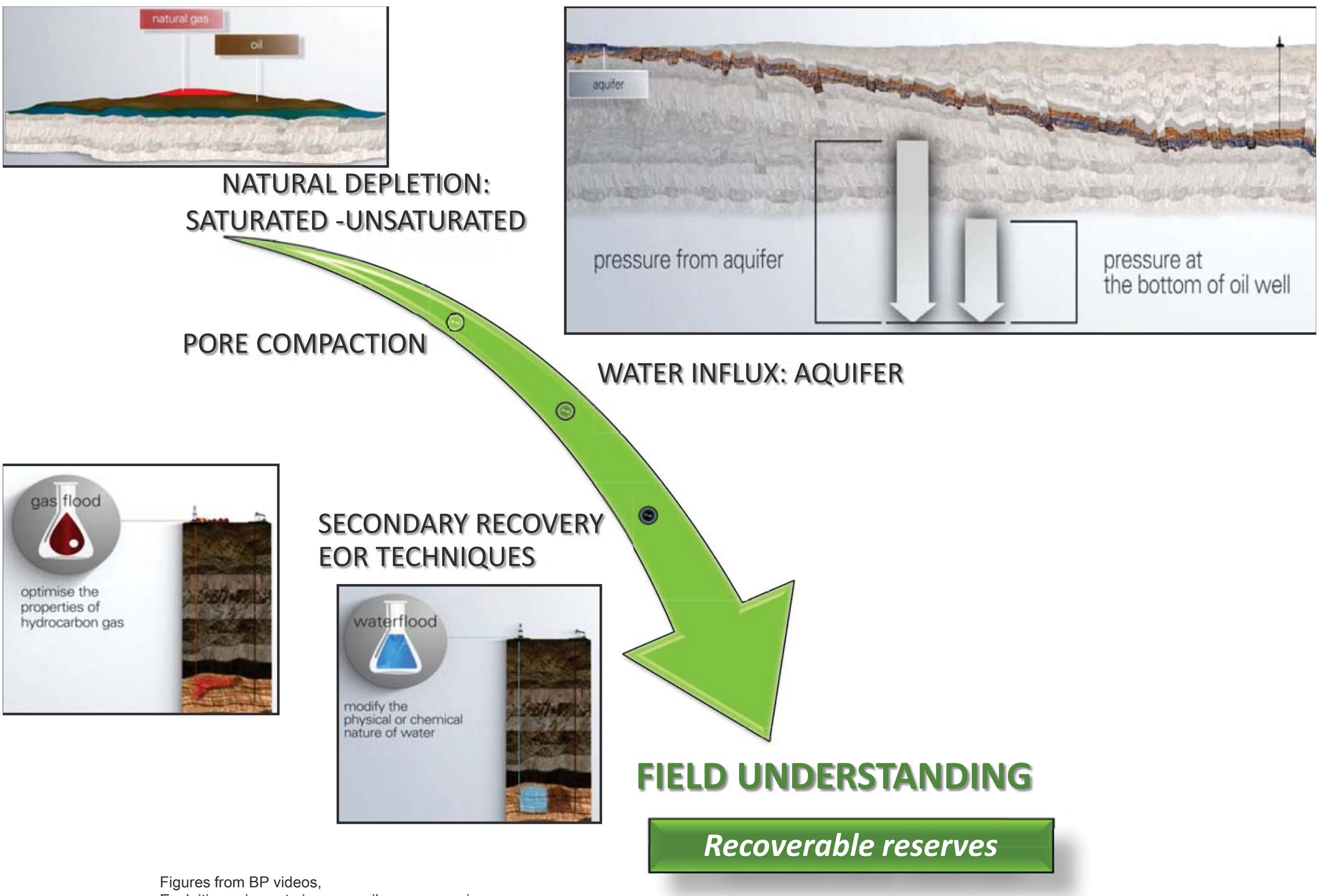
ENHANCED OIL RECOVERY

TERTIARY RECOVERY: energy for production is provided through complex methods

THERMAL
- Vapor
- In situ combustion

GAS
- Miscible Hydrocarbons
- CO_2
- N_2

CHEMICAL
- Polymer
- Surfactant



Figures from BP videos,
Exploiting science to increase oil recovery series

Introduction

- The choice of a development scheme is an approach that is both technical and economic
- To help the decision making process, it is necessary to estimate the future production of a field, over a period of many years
- It is therefore useful to understand the natural drive mechanisms, before deciding on the Secondary or Tertiary recovery mechanisms

Drive mechanisms and recovery

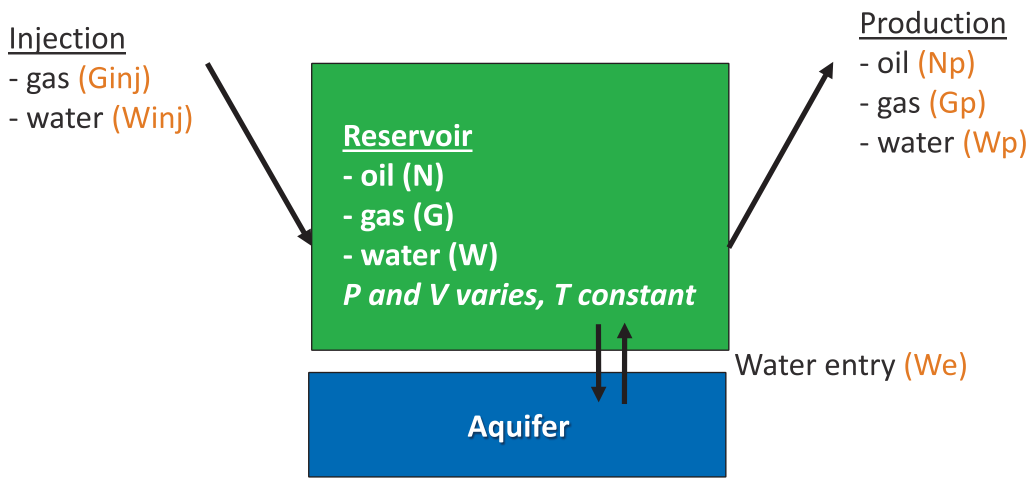
- Drive mechanism refers to the nature of the energy needed to drive the fluids out of the reservoir, into the wellbore
- Recovery mechanism refers to the manner by which the fluids are displaced and produced
- Energy is present in the reservoir as pressure
- Material Balance equation is the basic tool for the reservoir engineer to analyze the reservoir performance and behavior

2. Material balance

a. Principles

Principles of material balance

- In material balance calculation, the reservoir can be seen as a black box (no heterogeneities), whose pore volume varies (pore shrinkage), where fluids go in and go out, and whose pressure varies accordingly



N, G, W, Np, Gp, Wp, Ginj, Winj are volumes, expressed in standard conditions

Fluid expansion – Compressibility

- **Compressibility is related to the relative change in volume of an element when it is submitted to a variation of pressure**

$$c = -\frac{1}{V}\frac{dV}{dP} \qquad\qquad dV = -CVdP$$

- **We can express the volume in terms of formation volume factor, for example for oil:**

$$c_0 = \frac{-1}{B_o}\cdot\frac{dB_o}{dP} \qquad \text{then} \qquad c_o = -[(B_o - B_{oi})/B_{oi}]/(P - P_i)$$

- **Typical compressibility values**
  - c_0 = 1 to 3 x 10^{-4} bar $^{-1}$ (above bubble point)
  - c_w = 0.4 to 0.6 x 10^{-4} bar $^{-1}$
  - c_P = 0.3 to 1.5 x 10^{-4} bar $^{-1}$ (depending on nature of formation)
  - c_g = 5 to 150 x 10^{-4} bar $^{-1}$

2. Material balance

b. Undersaturated oil reservoirs

Natural depletion – Undersaturated oil

In undersaturated oil reservoirs, pressure declines very rapidly; GOR remains constant until reservoir pressure falls below bubble-point pressure

Material balance:

- **Assumptions:**
  - Fluid expansion
  - Pore volume reduction
  - No water entry (passive aquifer)

- **Produced volume = Increase of oil volume + Increase of volume of water + Decrease of pore volume**

- **Those variations of volumes are related to compressibility. Compressibility of oil, water and rock being generally pretty low, the expected recovery factor is low**

Natural depletion – Undersaturated oil

- **For a pressure drop from Pi to P (ΔP) with P > Pb (undersaturated oil):**
  - Oil volume increases by $(V_p \,.\, S_o \,.\, c_o) \,.\, \Delta P$
  - Water volume increases by $(V_p \,.\, S_{wi} \,.\, c_w) \,.\, \Delta P$
  - Pore volume shrinks by $(V_p \,.\, c_p) \,.\, \Delta P$

- **The cumulative production in standard conditions is defined as Np, then in reservoir conditions:**

$$Np.Bo = Vp.\Delta P(Co.So + Cw.Sw_i + Cp) = Vp.\Delta P.So\left(Co + \frac{Cw.Sw_i + Cp}{So}\right)$$

Let us define the effective compressibility, Ce: $Ce = \dfrac{Co.So + Cw.Sw_i + Cp}{So}$

Then: $Np = N\dfrac{Bo_i}{Bo}Ce.\Delta P$ and $RF = \dfrac{Np}{N} = \dfrac{Bo_i}{Bo}Ce.\Delta P$

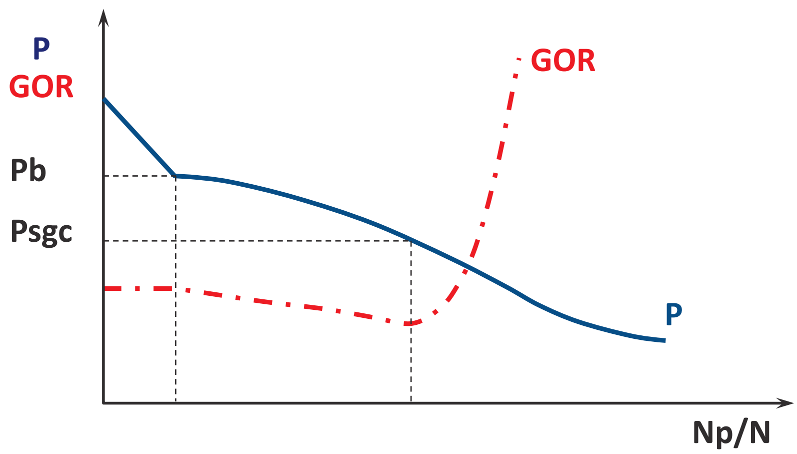
RF is defined as the recovery factor

2. Material balance

c. Solution gas drive

Natural depletion – Solution gas drive

- Reservoir pressure decreases under bubble point pressure
- Part of the gas dissolved in the oil is liberated in the reservoir
- Fluids and rock compressibility effects can be neglected vs. expansion of the liberated gas (gas compressibility is much bigger)
- Quick increase of the produced gas



Assuming **No gas cap**
No water influx

When P decrease below Pb, following Np and Gp production, the material balance equation becomes:

Initial Oil Volume = Remaining Oil Volume + Solution Gas Released

$$N.Bo_i = (N - Np).Bo + [(N.Rs_i - Gp) - (N - Np).Rs].Bg$$

Let us define the cumulative GOR as: $Rp = \dfrac{Gp}{Np}$

$$Np.[Bo + (Rp - Rs).Bg] = N.[(Bo - Bo_i) + (Rs_i - Rs).Bg]$$

Natural depletion – Solution gas drive

- **The recovery factor is expressed as:**

$$RF = \frac{N_p}{N} = \frac{(B_o - B_{oi}) + (R_{si} - R_s)B_g}{B_o + (R_p - R_s)B_g}$$

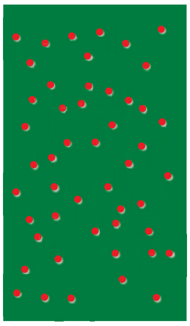
- **There is an inverse relationship between the oil recovery and the cumulative gas oil ratio Rp, then to obtain a good recovery, as much gas as possible should be kept in the reservoir, and production should be slow**

- **Negative effects of increase of gas saturation:**
  - Freeing solution gas will increase oil viscosity leading to reduce oil flowrate and oil production
  - Increasing gas saturation will lead to the decrease of oil relative permeability thus reducing oil flowrate and production

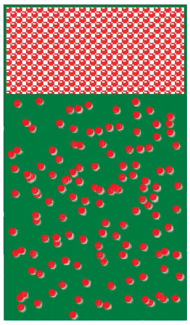
Dissolved gas drive

Critical gas saturation (Sgc)

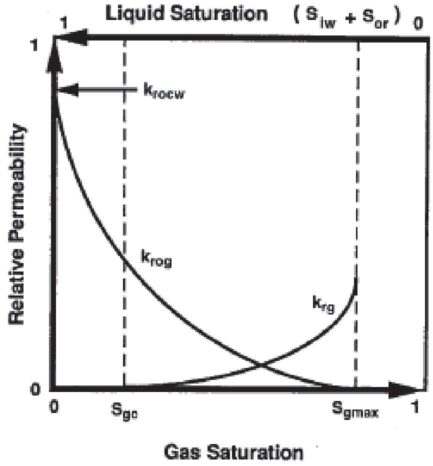
- Minimum gas saturation necessary for gas flow (Krg > 0)
- Laboratory measurements under reservoir conditions
- Sgc generally low



Sg < Sgc



Sg > Sgc



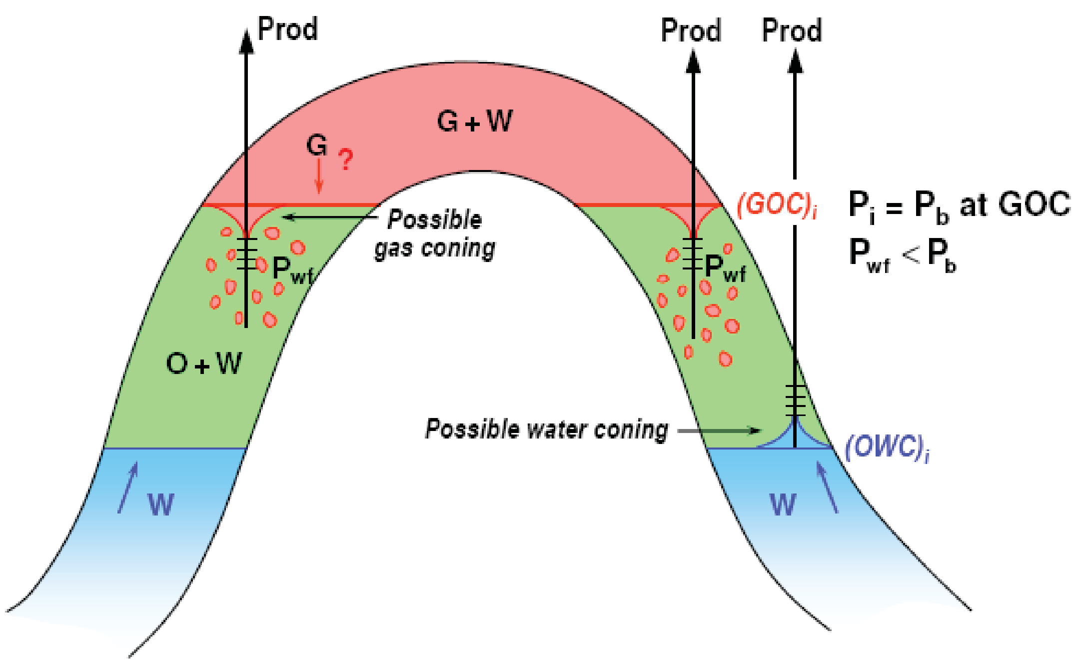
2. Material balance

d. Gas cap drive

Gas cap drive
General principles

- **Pressure decline associated with the production of oil will allow the gas cap to expand and provide further energy for production**
- **Reservoir performance:**
  - An efficient gas cap drive mechanism exhibits slow reservoir pressure decline and a slow oil production decline while GOR rises slowly and progressively
  - RF is generally higher than for solution gas drive reservoirs, up to 40%
  - Take care not to produce the gas cap
- **Conditions for effective gas cap drive**
  - Large Gas cap (gas cap volume vs volume of the oil zone)
  - Continuous homogenous reservoir
  - Good contact / communication between oil pool and gas cap
  - Good gravity segregation characteristics
    - Thick oil zone – High dip angle
    - High permeability – Particularly vertical permeability
    - Low oil viscosity
    - Low production rates

Gas cap expansion
Production strategy and well placement



Material balance equation

Material balance

- Adding the gas cap expansion to the solution gas drive equation (no water drive – neglecting water and pore volume compressibility)
- Let us define:

$$m = \frac{Volume\ of\ gas\ cap}{Volume\ of\ oil\ zone} = \frac{GB_{gi}}{NB_{oi}}$$

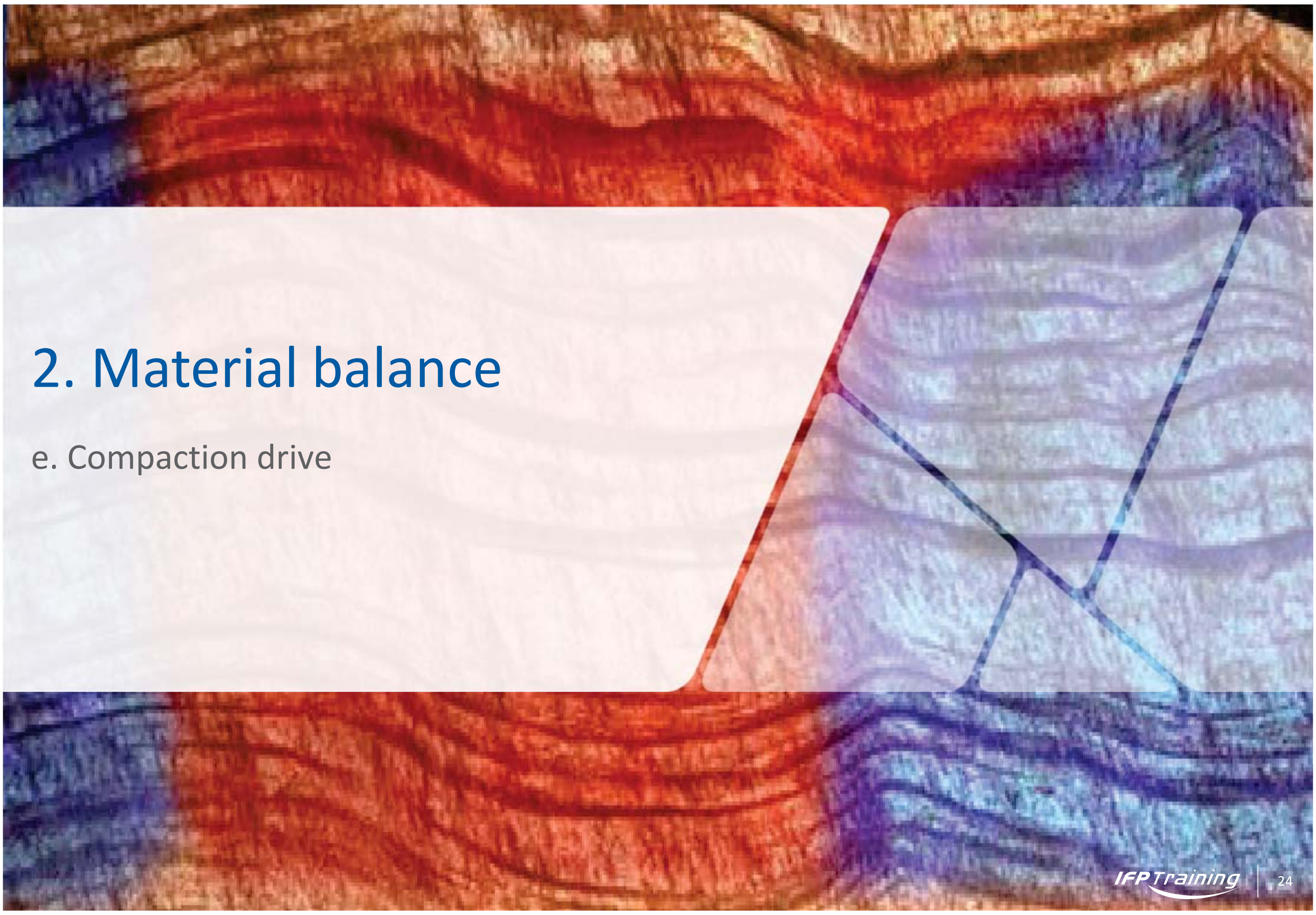
- Therefore: $G = m.N\frac{Bo_i}{Bg_i}$ @ Pi and $G.Bg = m.N.Bo_i\frac{Bg}{Bg_i}$ @ P << Pi

- Hence the gas cap expansion is given by:

$$G.Bg - G.Bg_i = m.N.Bo_i\frac{Bg}{Bg_i} - m.N.Bo_i = m.N.Bo_i\left(\frac{Bg}{Bg_i} - 1\right)$$

- Final material balance equation is given by:

$$Np.[Bo + (Rp - Rs).Bg] = N.\left[(Bo - Bo_i) + (Rs_i - Rs).Bg + m.Bo_i\left(\frac{Bg}{Bg_i} - 1\right)\right]$$



Compaction drive

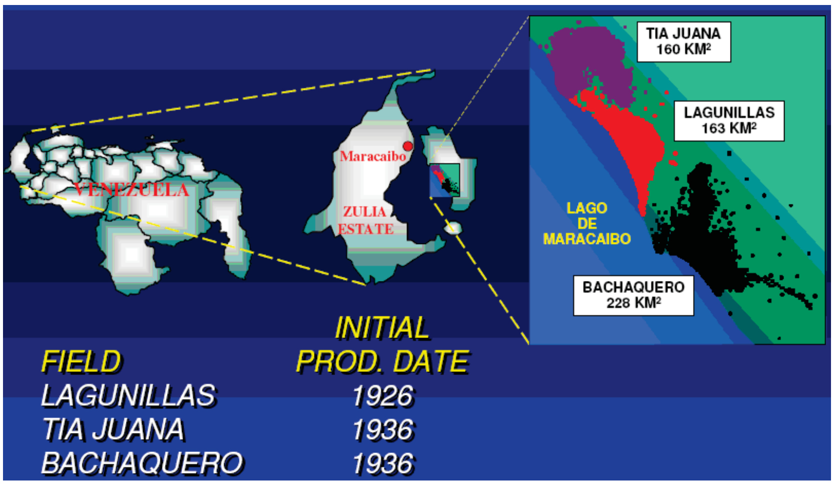
- As a reservoir gets depleted, its fluid pressure decreases (by ΔP), hence the effective pressure on the rock grains increases (by ΔP). Therefore the compaction of the rock is seen as a contraction of the pore volume ΔVf:

$$\frac{\Delta V_f}{V_f} = c_f \Delta p$$

- Where C_f, also called C_p, is the pore compressibility
- For most rocks, C_f is of the order of 3 to 10 10^{-6} psi^{-1}
- However, for some reservoirs, C_f can be much greater and compaction becomes significant as a drive mechanism

Maracaibo lake subsidence

- One such field is Bachaquero near Maracaibo (Venezuela)
- Bachaquero is one of the fields on the Bolivar Coast, where compaction reportedly yields oil recovery of up to 20%
- The chalk fields of the North Sea are also well known for compaction / subsidence, one of them being Ekofisk

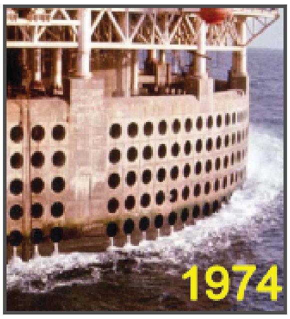


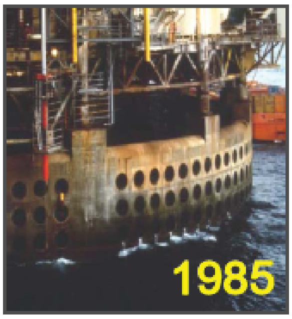
Ekofisk subsidence

GEV: Chalk fields - Impact of subsidence

- **Surface facilities to be replaced:**
  - Whiskey WHP replaced by SS Wat. Inj. 2010
  - Valhall VRD 2010/2011 (Living Quarters and Process)
  - Ekofisk Living Quarters 2013
  - Eldfisk II 2015 (WHP + LQ+ Process)
- **Wells to be constantly redrilled (average well life 10-15 years)**
- **4D effect visible on seismic: LoFS**

PLATFORM	SUBSIDENCE RATE 12 month (cm/yr)	SUBSIDENCE RATE 4 month (cm/yr)	SUBSIDENCE RATE 12 month (cm/yr)	SUBSIDENCE RATE 4 month (cm/yr)	TOTAL SUBSIDENCE (meters)
2/4 HOTEL	11.5	14.4	11.7	14.2	9.277
2/4 ALPHA	13.5	14.6	13.7	15.2	[illegible]
2/4 BRAVO	9.2	8.2	8.8	7.1	5.412
2/4 J*	13.7	16.8	13.8	14.6	3.828
2/7 ALPHA*	2.4	2.9	2.5	2.7	1.644
2/7 BRAVO*	4.0	4.4	4.2	5.1	1.728
2/7 EMBLA	0.9	1.4	0.9	1.1	0.085





Ekofisk II replaced in 1998 the old Ekofisk I facilities

2. Material balance

f. Water drive

Water drive

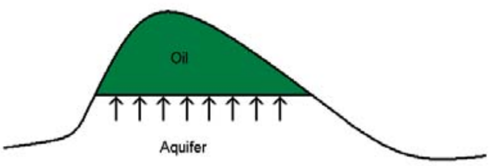
General principles

- Primary source of energy is provided by water influx into the reservoir which results in pressure maintenance
- In most cases, the energy comes from aquifer compressibility: Ca = Cp + Cw
- Water drive effectiveness is a function of the aquifer connexion in the short term and the aquifer volume in long term
- Total fluid rate remains generally constant, and if reservoir pressure is kept above bubble-point, GOR remains constant while WOR increases steadily
- Oil recovery can reach value as high as 60% with an average of 35 to 40%

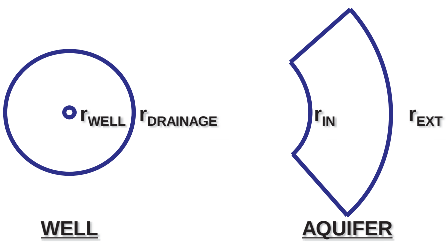
Water drive

Aquifer configuration

- The bottom water drive aquifer: it is in contact with the entire hydrocarbon area. Water invasion occurring vertically is governed by the reservoir vertical permeability.



- The edge water drive aquifer: the water entries take place laterally. Horizontal permeability is governing the water mouvement.



Natural water influx
Material balance

- **Assuming P_b << P (for simplicity)**
  a. Oil volume expands
  b. Water volume expands
  c. Pore volume decreases
  d. Aquifer expands => Water entry W_e
  e. Water production W_p
- **Oil production = a + b + c + d – e**

$$Np.Bo = N.Bo_i.Ce(Pi - P) + We - Wp.Bw$$

$$RF = \frac{Np}{N} = \frac{Bo_i}{Bo}Ce(Pi - P) + \frac{We}{N.Bo}$$

- **The water entry depends on the aquifer model, considering an instantaneous expansion:**

$$We = Ca.Vw.(Pi - P)$$

$$Ca = Cw + Cp$$

Natural water influx
Water entry calculation

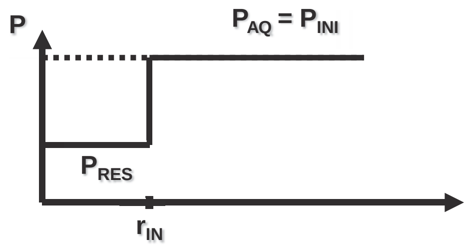
Aquifer models

1. **Small pot: Independent time equation** $We = Ca.Vw.(Pi - P)$

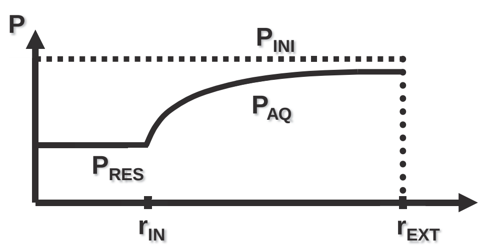
2. **Pseudo steady state: Fetkovich**

$$\Delta We = J.(Pi - P).\Delta t$$

J is the Fetkovich productivity index



3. **Transient: Carter Tracy model, approximate solution to diffusivity equation**



2. Material balance

g. Gas fields

Gas fields

Some definitions about gas reservoirs

- **For gas reservoirs, the different gas definitions refer to the PVT behavior of the gas which depends on the initial reservoir gas composition, initial reservoir pressure and temperature**

- **A gas reservoir is a reservoir in which hydrocarbons remain in the gaseous state throughout the life of the reservoir**
  - Dry Gas reservoir
    - The gas in the reservoir is always monophasic, whatever the reservoir pressure
    - No liquid condensation occurs from reservoir through surface (separator)
  - Wet Gas reservoir
    - The gas in the reservoir is always monophasic, whatever the reservoir pressure
    - At surface conditions, associated liquid is produced simultaneously with gas
  - Gas condensate
    - Part of the gas condenses in-situ when the pressure decreases

Gas fields

Material Balance, no water entry

- **Let us assume no water entry**
- **Water and rock compressibility are neglected compared to gas compressibility**
- **When pressure drops, the volume occupied by the gas under reservoir conditions does not change → initial gas accumulation = gas accumulation @ (P,T)**

$$G.Bg_i = (G - Gp)Bg \quad \rightarrow \quad Gp = G\left(1 - \frac{Bg_i}{Bg}\right)$$

Where:

G is the initial accumulation of gas at standard conditions

Gp is the gas production at standard conditions

- **From EOS:** $\frac{Bg_i}{Bg} = \frac{Z_i}{P_i} \times \frac{P}{Z} \quad \rightarrow \quad Gp = G\left(1 - \frac{Z_i}{P_i} \times \frac{P}{Z}\right)$

Gas fields

Recovery factor, no water entry

$$RF = \frac{Gp}{G} = 1 - \frac{Bg_i}{Bg} = 1 - \frac{Z_i}{P_i} \times \frac{P}{Z}$$

- **Recovery is a function of:**
  - Original reservoir pressure
  - Current reservoir pressure
  - Gas mixture composition
- **Recovery is not a function of time**
- **It is assumed that the reservoir depletes in the same manner everywhere**
- **Corresponding RF can be very high, up to 90-95% (e.g. Lacq)**

Gas fields

Material Balance, water entry

- **Still neglecting water and formation compressibilities compared to gas compressibility, the generalized material balance equation writes:**

  net fluid withdrawal = fluids expansion in the reservoir + cumulative water influx

- **The net fluid withdrawal is given by:** $Gp.Bg + Wp.Bw$

- **The gas expansion is:** $G(Bg - Bg_i)$

- **Generalized Material Balance for a gas reservoir is given by:**

$$Gp.Bg = G(Bg - Bg_i) + We - Wp.Bw$$

Gas fields

Recovery factor, water entry

$$RF = \frac{Gp}{G} = 1 - \frac{Bg_i}{Bg} + \frac{1}{G.Bg}(We - Wp.Bw)$$

$$RF = \frac{Gp}{G} = 1 - \frac{Z_i}{P_i} \times \frac{P}{Z} + \frac{1}{G}(We - Wp.Bw)\frac{P}{Z}\frac{T_{sc}}{P_{sc}}\frac{1}{T}$$

- **Recovery is function of:**
  - Initial reservoir pressure
  - Actual reservoir pressure
  - Gas mixture composition
  - Time (through We)

Gas reservoirs behavior

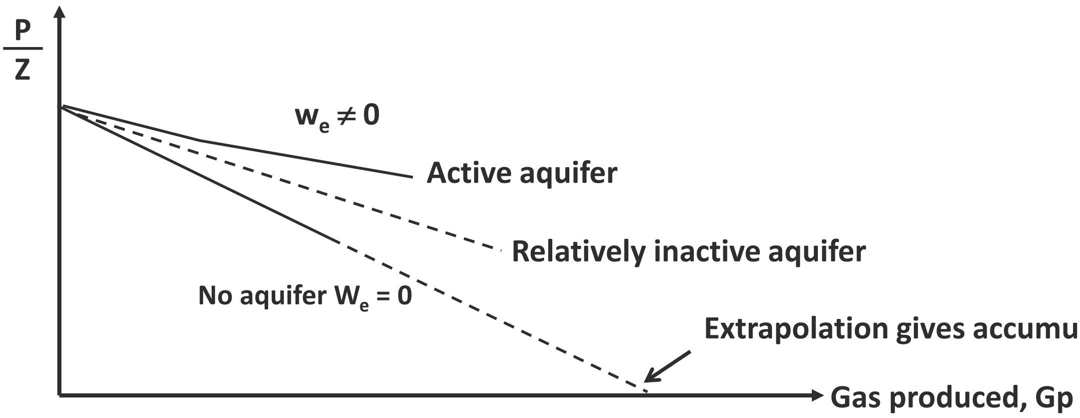
Plotting P/Z versus Gp

- It is a straight line for a closed reservoir (no water entry)
- Extrapolation of the line gives estimate of the accumulation *G*

$$Gp = \boxed{G\left(1 - \frac{Z_i}{P_i} \times \frac{P}{Z}\right)}$$

- With water entry, the straight line becomes exponential in case of active aquifer

$$Gp = \boxed{G\left[1 - \frac{Z_i}{P_i} \times \frac{P}{Z}\right]} + (We - Wp.Bw)\frac{P}{Z}\frac{T_{sc}}{T}$$



Natural drive mechanism of an opened reservoir

- **Let us take the general case of a reservoir with an oil rim overlain by a gas cap and underlain by an aquifer**
- **The oil rim is produced and the production at surface will consist of oil, gas and water**
- **The volumetric material balance expressed at reservoir conditions is:**

Initial volume occupied by the oil =
oil volume left in the reservoir with its dissolved gas
+ liberated gas from oil and staying in the reservoir
+ gas volume from the initial gas cap invading the oil zone
+ water entry
– produced water

Generalized material balance

- **The material balance equation becomes:**

$$N.Bo_i = (N - Np)Bo + [(N.Rs_i - Gp) - (N - Np)Rs]Bg$$
$$+m.N.Bo_i\left(\frac{Bg}{Bg_i} - 1\right) + We - Wp.Bw$$

- **Introducing *Rp* definition:** $Rp = \frac{Gp}{Np}$

$$Np[Bo + (Rp - Rs)Bg] = N[(Bo - Bo_i) + (Rs_i - Rs)Bg]$$
$$+m.N.Bo_i\left(\frac{Bg}{Bg_i} - 1\right) + We - Wp.Bw$$

4. Summary – Key points

Key points to keep in mind

Fluid expansion & pore volume reduction

- **Occurs when only one phase is mobile in the reservoir**
  - Undersaturated oil reservoirs as well as Gas and gas-condensate reservoirs produce by fluid expansion and pore volume reduction

- **Reservoir performance**
  - In undersaturated oil reservoirs pressure declines very rapidly; GOR remains constant until reservoir pressure falls below bubble-point pressure
  - For Gas reservoirs recoveries reach high value due to the combination of two specific characteristics
    - Low gas viscosity
    - High compressibility

Key points to keep in mind

Solution gas drive

- **The solution gas drive mechanism: describes oil displacement by the expansion of gas released from solution as pressure is reduced below bubble point**
  - As oil and gas production goes on, pressure declines further, more gas is released from solution
  - Gas flow increases, oil flow decreases, as a result of the increasing gas saturation in the reservoir and of unfavorable relative permeability evolution
- **Reservoir performance**
  - Solution gas drive reservoirs exhibit typically rapid reservoir pressure decline and correspondingly, rapid oil production decline
  - GOR rises rapidly from initial value to a maximum value, before declining rapidly
  - Oil recovery is generally low, typically ranging from 5 to 25 %

Key points to keep in mind

Gas cap drive

- **In presence of a gas cap above an oil zone, the pressure decline associated with the production of oil will allow the gas cap to expand and provide energy to produce the oil**
  - To be effective, a large gas cap is necessary (initial or secondary gas cap)
  - For a secondary gas cap to form, high vertical permeability associated with a relatively homogeneous reservoir are needed
- **Reservoir performance**
  - An efficient gas drive mechanism exhibits typically slow reservoir pressure decline and a slow oil production decline
  - GOR rises slowly and progressively
  - Oil recovery is generally higher than for solution gas drive reservoirs and depends highly upon the vertical permeability

Key points to keep in mind

Water drive

- **For a water drive reservoir, the pressure primary source of energy is supplied by water influx (from an adjacent aquifer) into the reservoir**
  - In most cases, the energy for this water movement comes from expansion of the rock and the water in the aquifer

- **Reservoir performance**
  - Water drive effectiveness is a function of the properties of the aquifer and not of the reservoir
  - The two key parameters are the aquifer size and the aquifer transmissibility (i.e. permeability x thickness)
  - Total fluid rate remains generally constant, and if reservoir pressure is kept above bubble-point, GOR remains constant. It is characteristic to see a steady increase in WOR
  - Oil recovery can reach value as high as 40 to 80 %

Key points to keep in mind

Gas reservoirs

- **Without water entry and neglecting water and pore volume compressibility**
  - reservoir is produced through gas expansion only
  - RF is a linear function of P/Z and is no time dependent
  - RF can reach very high values, typically 90-95%

- **With water entry**
  - decrease of gas saturation and risk of flooding producers
  - Risk of trapping high pressure gas; the volume of trapped gas is a decreasing linear function of P/Z; therefore we want the gas to be trapped at the lowest pressure as possible → it is recommended to produce fast
  - RF is still a function of P/Z but no longer linear and is time dependent
  - RF is lower than without water entry, typically down to 50-70%

Fundamentals of Reservoir Engineering – Drive mechanisms Secondary recovery

Week#2

PTTEP Algeria

November 2016

Outline

1. **Introduction**
2. **Multiphase flow**
   a. Frontal displacement
   b. Buckley-Leverett theory
3. **Mobility ratio**
4. **Sweep efficiency**
5. **Injection characteristics**
6. **Water and gas injection**
7. **Summary**

1. Introduction

Introduction to Secondary Recovery

Principles

- **Natural drainage often leads to low recovery factor for oil fields**
  - Energy has to be injected into the reservoirs in order to achieve better recovery
  - First process used after reservoir depletion is injection of fluid in the reservoir (water/gas) → Secondary Recovery
- **Objectives: increase reserves by**
  - Maintaining the reservoir pressure
  - Improving sweep efficiency of the hydrocarbons
- **Methods**
  - Water injection (in the aquifer or in the structurally lowest part of the oil zone)
  - Gas injection (in the gas cap or in the top of the oil zone)

Evaluation of drive mechanisms

- **Reservoir engineers may have to decide, from the onset, what will be the drainage mechanisms: natural depletion or assisted drainage (water or gas injection, steam injection…)**

- **However, assisted drainage is rarely implemented right from the beginning**

- **It is preferable to start producing the field by natural depletion, even for a very short period, in order to observe the field behavior and decide on the nature of the drainage mechanism from the dynamic data**

- **As we learn more about the reservoir, the initial Field Development Plan may evolve**

Parameters to define/optimize

- **A number of parameters needs to be defined/optimized**
  - Fluid to be injected (water/gas)
  - Injection zone (top, bottom, aquifer, all…)
  - Injection pattern (grouped flood, dispersed flood...)
  - Optimum level of pressure maintenance → injection rate, injection pace (continue, alternate…)
    - Number of injection wells
    - Planning of investment
  - Field surveillance and data acquisition to monitor the results of injection strategy implementation vs. forecast
  - Data input for well architecture/completion design and for surface facilities design

Studies

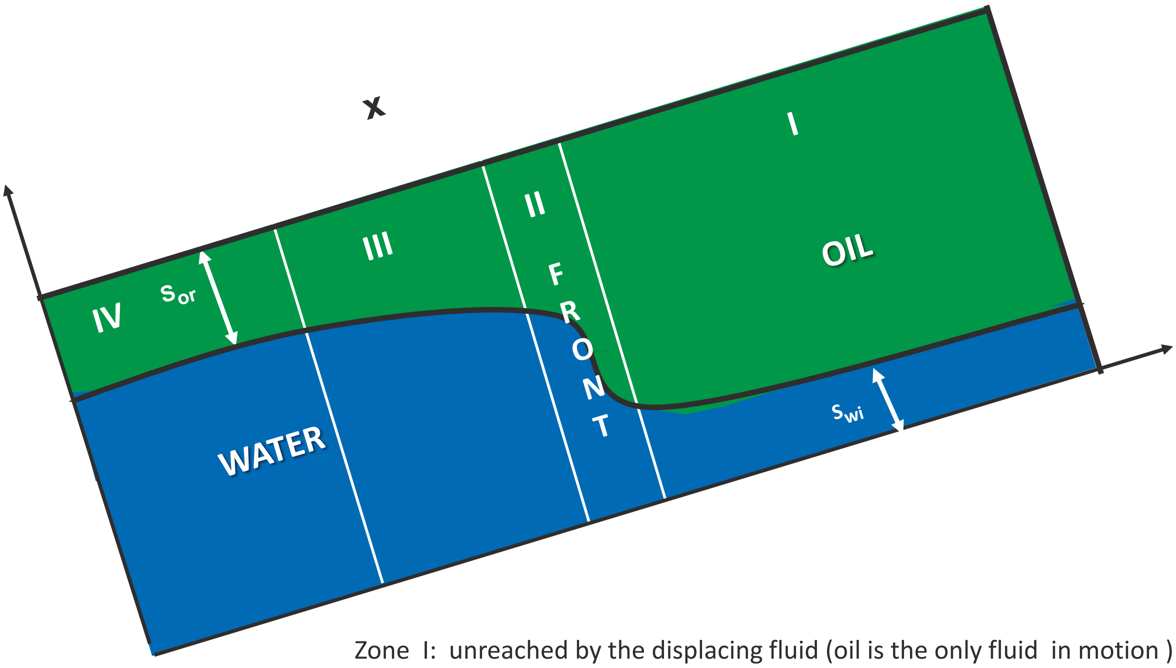
- **Feasibility study mandatory to implement Secondary Recovery**
- **Project design should include simulation and analytical methods**
- **Laboratory tests are mandatory**
  - SCAL (wettability, relative permeability, capillary pressure)
  - Water flooding and gas flooding at reservoir conditions
  - Water compatibility issues
  - Clay swelling issues
  - Fine mobilization issues

2. Multiphase flow

a. Frontal displacement

Frontal displacement

Multiphase flow



Zone I: unreached by the displacing fluid (oil is the only fluid in motion)

Zone II: S_w increases rapidly at the front

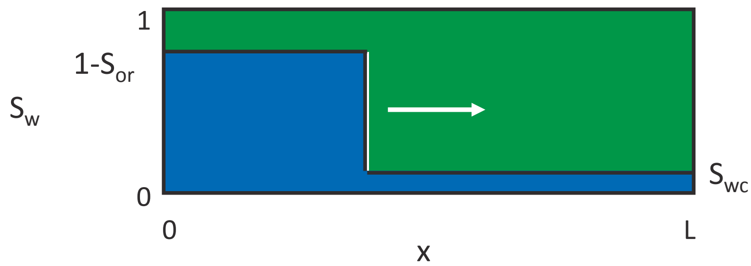
Zone III: S_w varies gradually behind the front

Zone IV: flooded by water (water is the only fluid in motion), S_{or}

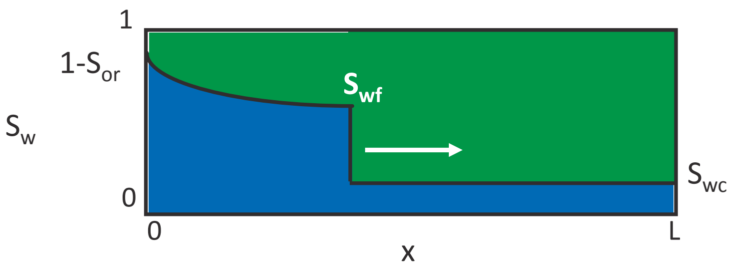
Fluid Flow Behavior:

Displacement in Production... 1D

- **IDEAL: piston-like displacement**



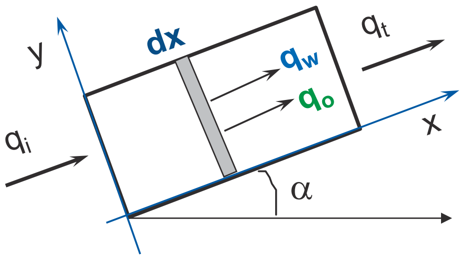
- **REAL: function of kr, μ, k, ρ, q, dip angle**



Frontal displacement theory

- **Assumptions**
  - Homogeneous and water wet medium
  - 1D displacement, diffuse flow conditions: fluid saturation is only a function of x and is uniformly distributed with respect of thickness
  - Oil and water are non compressible and non miscible fluids
  - Displacement of oil by injected water at steady conditions.
    - Pressure in any point of the reservoir remains constant
    - In reservoir conditions qt = qo + qw

- **Playing forces : Viscous, Capillary & Gravity**



Frontal displacement theory

- **Let us define the fractional flow (rates in reservoir conditions):**

$$f_w = \frac{q_w}{q_w + q_o}$$

- **Using Darcy's law and considering gravity, viscous and capillary effects, we can derive**

$$f_w = \underbrace{\frac{1}{1+\frac{\mu_w . k_o}{\mu_o . k_w}}}_{\text{viscous term}} + \underbrace{\frac{A.k_o}{\mu_o . q_t \cdot \left(1+\frac{\mu_w . k_o}{\mu_o . k_w}\right)}}_{\text{capillary term}} \cdot \frac{\partial P_c}{\partial x} + \underbrace{\frac{A.k_o \cdot (\rho_w - \rho_o).g.\sin\alpha}{\mu_o . q_t \cdot \left(1+\frac{\mu_w . k_o}{\mu_o . k_w}\right)}}_{\text{gravity term}}$$

- **Neglecting capillary and gravity forces, the fractional flow becomes:**

$$f_w = \frac{1}{1 + \frac{\mu_w . kr_o}{\mu_o . kr_w}}$$

2. Multiphase flow

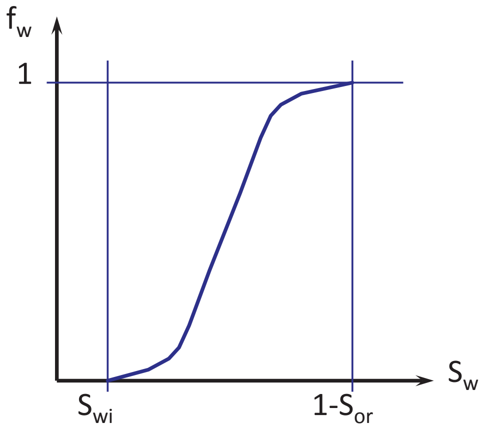
b. Buckley Leverett theory

Buckley-Leverett theory

- **So, considering only the viscous forces:**
  - No capillarity → Pc=0
  - No gravity → α = 0 (no dip)

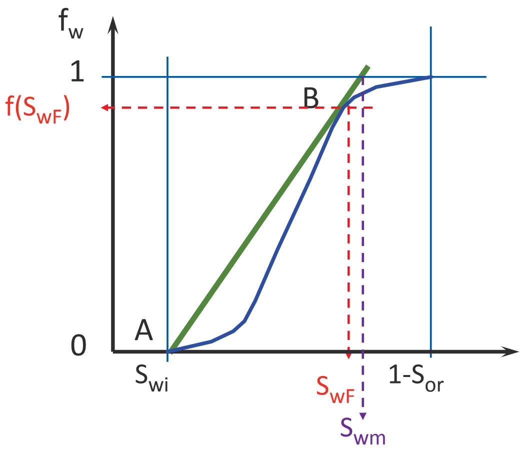
$$f_w = \frac{1}{1 + \frac{\mu_w . kr_o}{\mu_o . kr_w}}$$

- **Fractional flow is a function of Sw**



Welge tangent method

- Line A-B is tangent to the $fw(Sw)$ curve at the point where Sw = **Sw_F** (saturation at front)



- Similarly, one could derive that the intersect of the tangent with fw = 1 gives the average saturation behind the front **Swm**

Fractional flow (fw) versus water cut (or BSW)

- q_o and q_w are the oil and water rates in reservoir conditions, we got:

$$f_w = \frac{q_w}{q_w + q_o} \quad (1) \qquad BSW = \frac{\frac{q_w}{B_w}}{\frac{q_w}{B_w} + \frac{q_o}{B_o}} \quad (2)$$

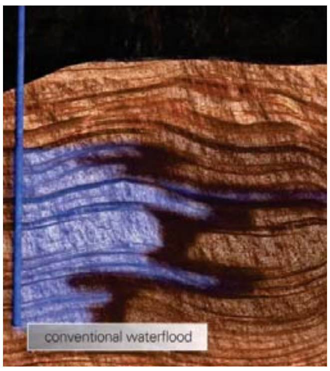
$$f_w = \frac{1}{1 + \left[\frac{B_o}{B_w} \cdot \left(\frac{1}{BSW} - 1\right)\right]} \qquad BSW = \frac{1}{1 + \frac{B_w}{B_o} \cdot \left(\frac{1}{f_w} - 1\right)}$$

- Then water saturation at the front and average behind the front can be calculated for water breakthrough and any water cut

3. Mobility ratio

Front / interface distortion

- When reservoir thickness is more important, the interfaces and the "fronts" can be unstable and be subsequently distorted (tongue, fingering…)



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- The stability of the displacement front is a function of the Mobility Ratio M

Mobility ratio

$$M = \frac{\text{mobility of displacing phase}}{\text{mobility of displaced phase}}$$

$$M_{w/o} = \frac{\text{water mobility}}{\text{oil mobility}} = \frac{k_{rw} / \mu_w}{k_{ro} / \mu_o} = \frac{k_{rw}\,\mu_o}{k_{ro}\,\mu_w}$$

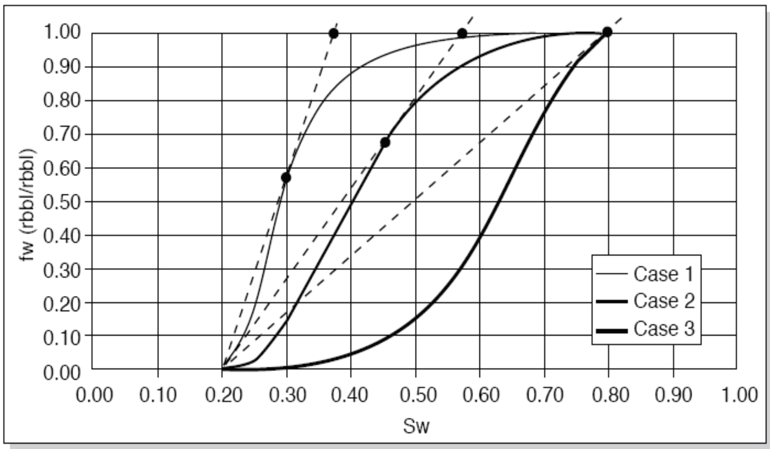
$$M_{g/o} = \frac{\text{gas mobility}}{\text{oil mobility}} = \frac{k_{rg} / \mu_g}{k_{ro} / \mu_o} = \frac{k_{rg}\,\mu_o}{k_{ro}\,\mu_g}$$

M<1: favorable displacement **M>1: unfavorable**

Multiphase flow

Effect of mobility ratio

- **Lower ratios M shift the fractional flow curve to the right**
- **Favorable M (<1) lead to high values of S_{wm} near to maximum water saturation**
- **Unfavorable M (>1) lead to low values of S_{wm} far from maximum water saturation → more oil trapped behind the front**



4. Sweep efficiency

Sweep efficiency

Definition

- **Sweep efficiency corresponds to the recovery factor (in reservoir conditions) for areas undergoing injection**

$$E = RF = \frac{Np.Bo}{Vp.So_i}$$

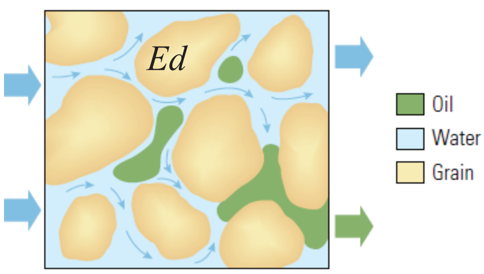
where So_i is the oil saturation at the start of injection

- **Sweep efficiency can be expressed by:** $E = E_d.E_a.E_v$

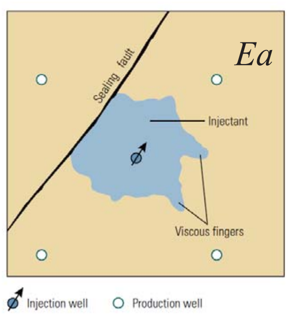
Ed is the displacement (or pore scale) efficiency

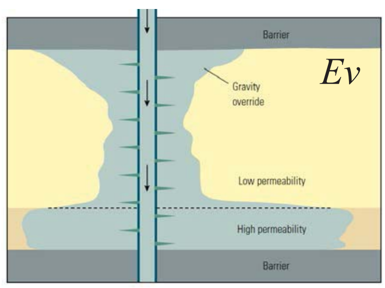
Ea is the areal sweep efficiency

Ev is the vertical efficiency



Rifaat Al-Mjeni et al.,
Oilfield Review, SLB. Winter 2010/2011

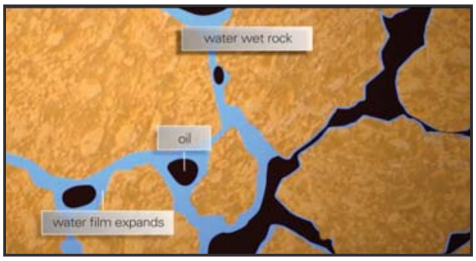


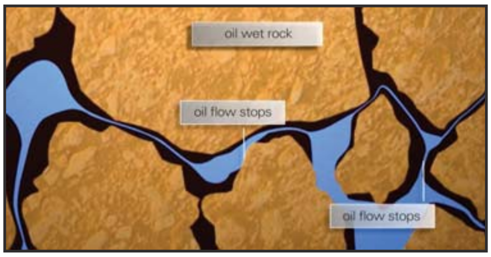


Water injection

- **Displacement efficiency at the pore scale depens on:**
  - Natural depletion
  - Wettability
  - Mobility ratio: relative permeability & viscosity

$$E_d = \frac{So_i - So}{So_i}$$





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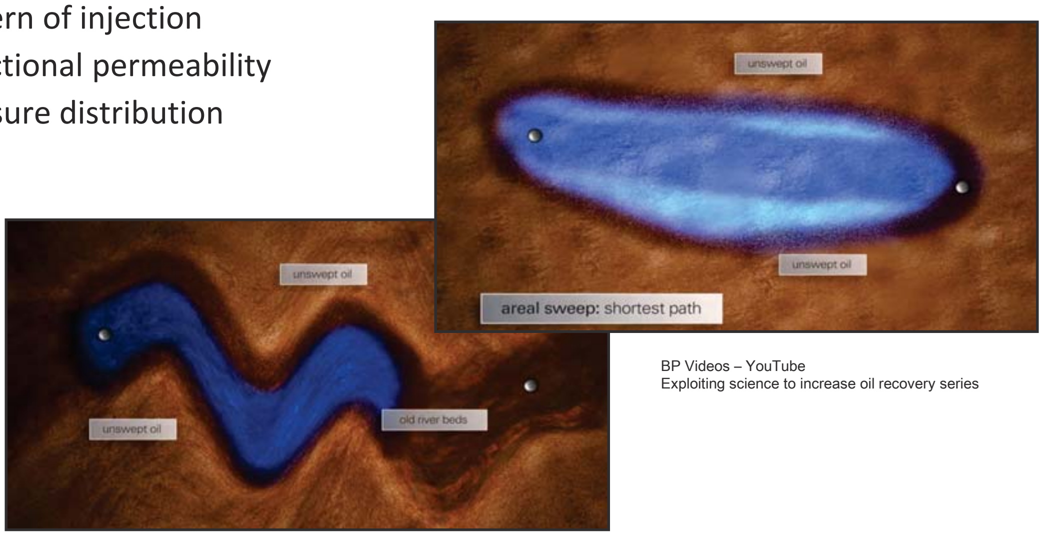
At the microscopic scale, oil can be trapped in the middle of pores when water flows around the oil in a water-wet formation. Oil that is connected to flow paths continues to be displaced.

Water injection

- **Areal efficiency depens on:**
  - Mobility ratio: relative permeability & viscosity
  - Pattern of injection
  - Directional permeability
  - Pressure distribution



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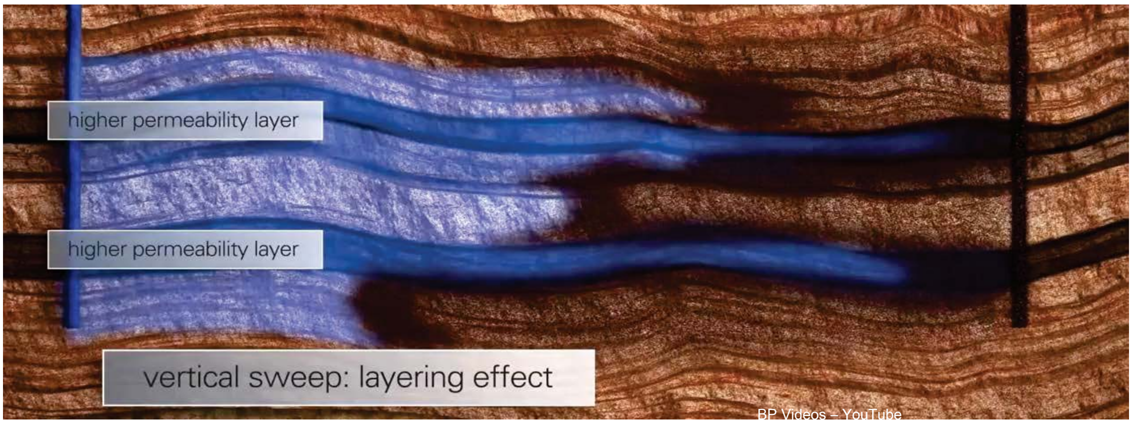
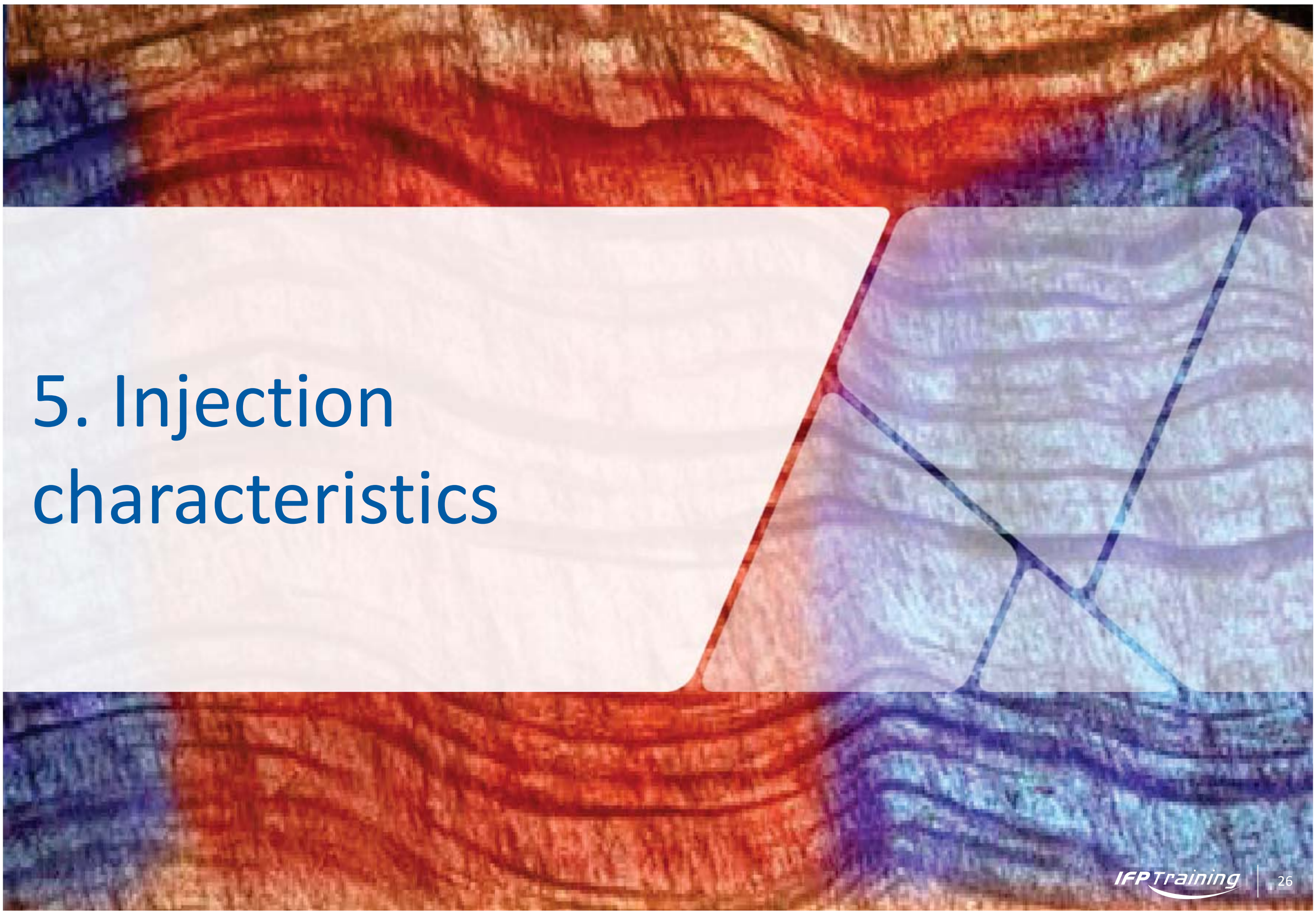
Oil can be bypassed because of inefficiencies in macroscopic sweep. A pattern flood can be affected by a heterogeneous formation or by fingering of a less viscous injectant into the oil.

Water injection

- **Vertical efficiency depens on:**
  - Rock properties variation between different flow units



Vertical sweep can be affected by viscous fingering, as well as by preferential movement of fluids along a high-permeability thief zone or by gravity override of injection gas or underride of injection water.



5. Injection characteristics

Injection characteristics
Volume of fluid injected

- **For reservoir pressure to be strictly maintained, voidage replacement has to be insured**
- **If no other mechanisms are involved (like active aquifer), the injected volume should compensate the produced volumes in reservoir conditions:**

Injection rate = production rate (@ res. conditions)

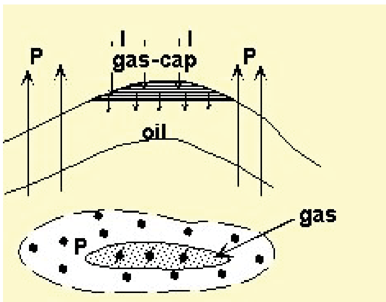
$$Q_{inj}B_{inj} = Q_oB_o + Q_{wp}B_{wp} + Q_{fg}B_{fg}$$

where Q_{fg} is the surface flowrate of free gas $Q_{fg} = Q_o(GOR - R_s)$

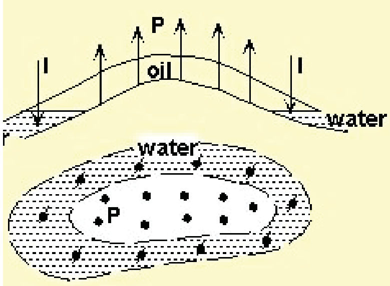
- **Actually, injected volume will also depend on available fluid for injection**
- **Injection characteristics are:**
  - Volumes of fluid injected
  - Type of fluid injected
  - Injection pattern

Injection characteristics
Grouped injection pattern

- **In the case of high-dip or high permeability reservoir, injection wells are placed to get a regular displacement i.e. piston-like allowing to sweep large areas with very late breakthrough at the production wells → grouped pattern**



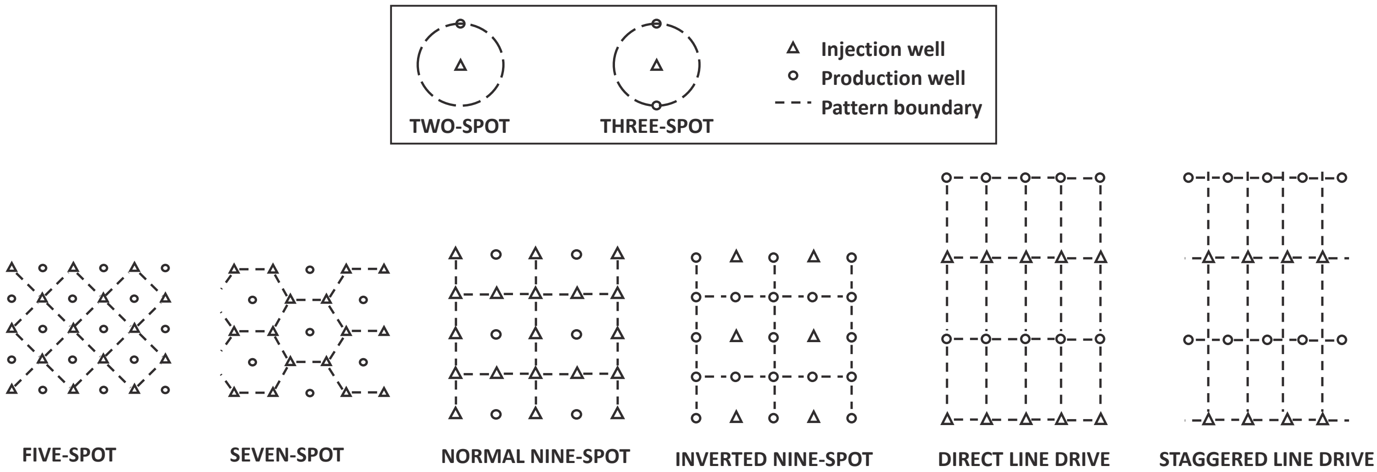
- **In case of gas, injection is made in the gas-cap, if it exists, close to the GOC → cluster injection**

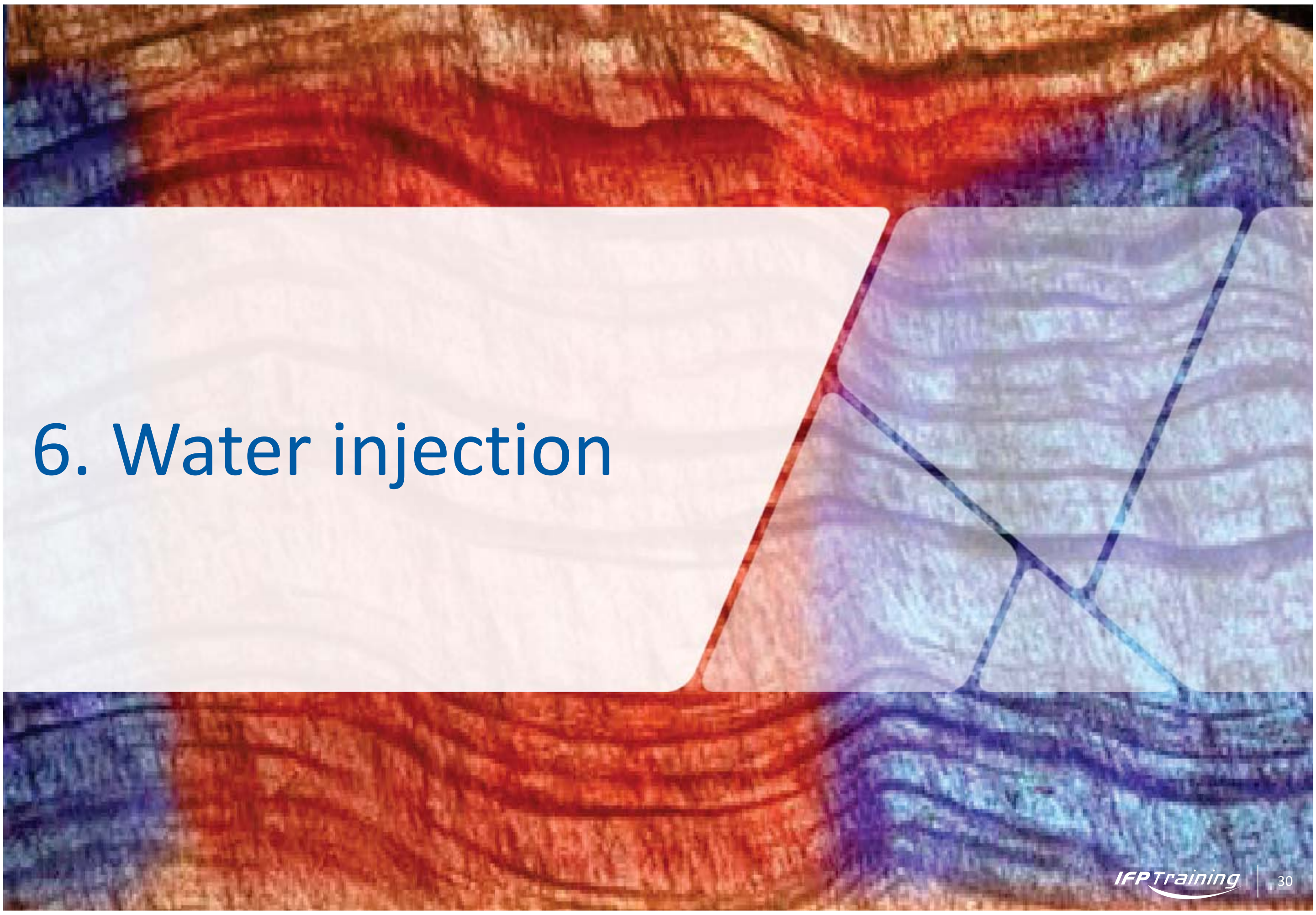


- **In case of water, injection is made in the aquifer, near the WOC → peripheral injection**

Dispersed injection pattern

- In the case of low-dip or low permeability reservoir, injection wells are placed in a regular way near the producers in the oil zone → dispersed pattern





6. Water injection

Water injection

- Water injection is the most commonly used Secondary Recovery process especially because of water availability

- It helps improve recovery and accelerate field production, through voidage replacement

- Mobility ratio is usually favorable, especially for light/medium oil; and in any case, it is more favorable than for gas injection; however residual oil saturation may be quite high (20-30%)

- Recovery factor can be as high as 50-60%

Water injection
Well injectivity

- Injectivity index (II) will depend on well location:

$$II = \frac{\alpha \cdot kh \cdot krw}{Bw \cdot \mu w \cdot [\ln(r_d / r_w) + S - 0.75]}$$

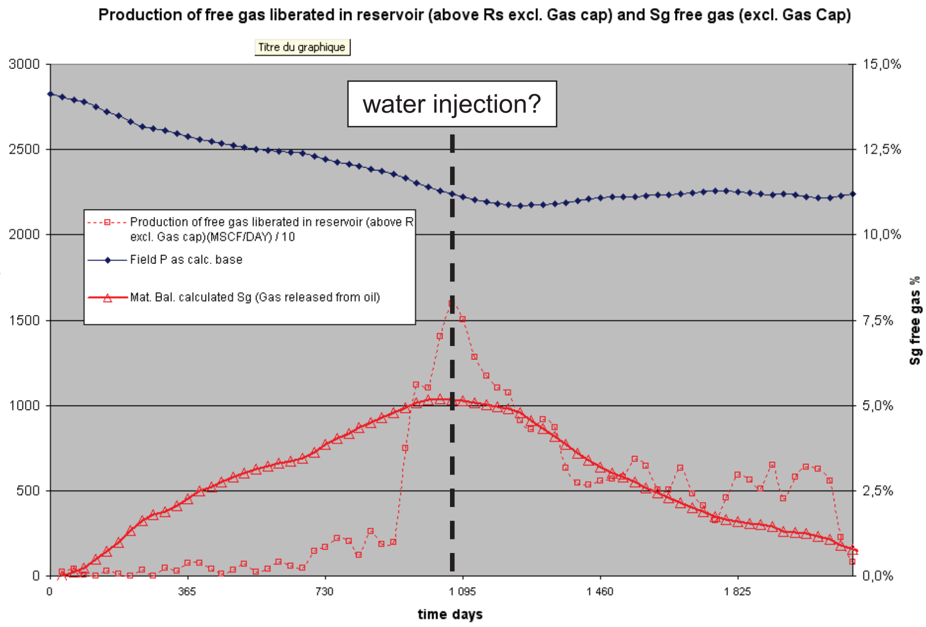
$$\alpha = 0.0086 \cdot 2\pi = 0.0536 \quad \rightarrow \quad metric\ units$$
$$\alpha = 0.001127 \cdot 2\pi = 0.00708 \quad \rightarrow \quad field\ units$$

In the water zone krw = 1

Water injection

Timing of injection

- **Too early**
  - Difficult to check presence of natural aquifer
  - Require high injection pressure
  - Advantage, higher pressure allow high production
- **Too late**
  - As P goes below bubble point, GOR increases while Q decreases

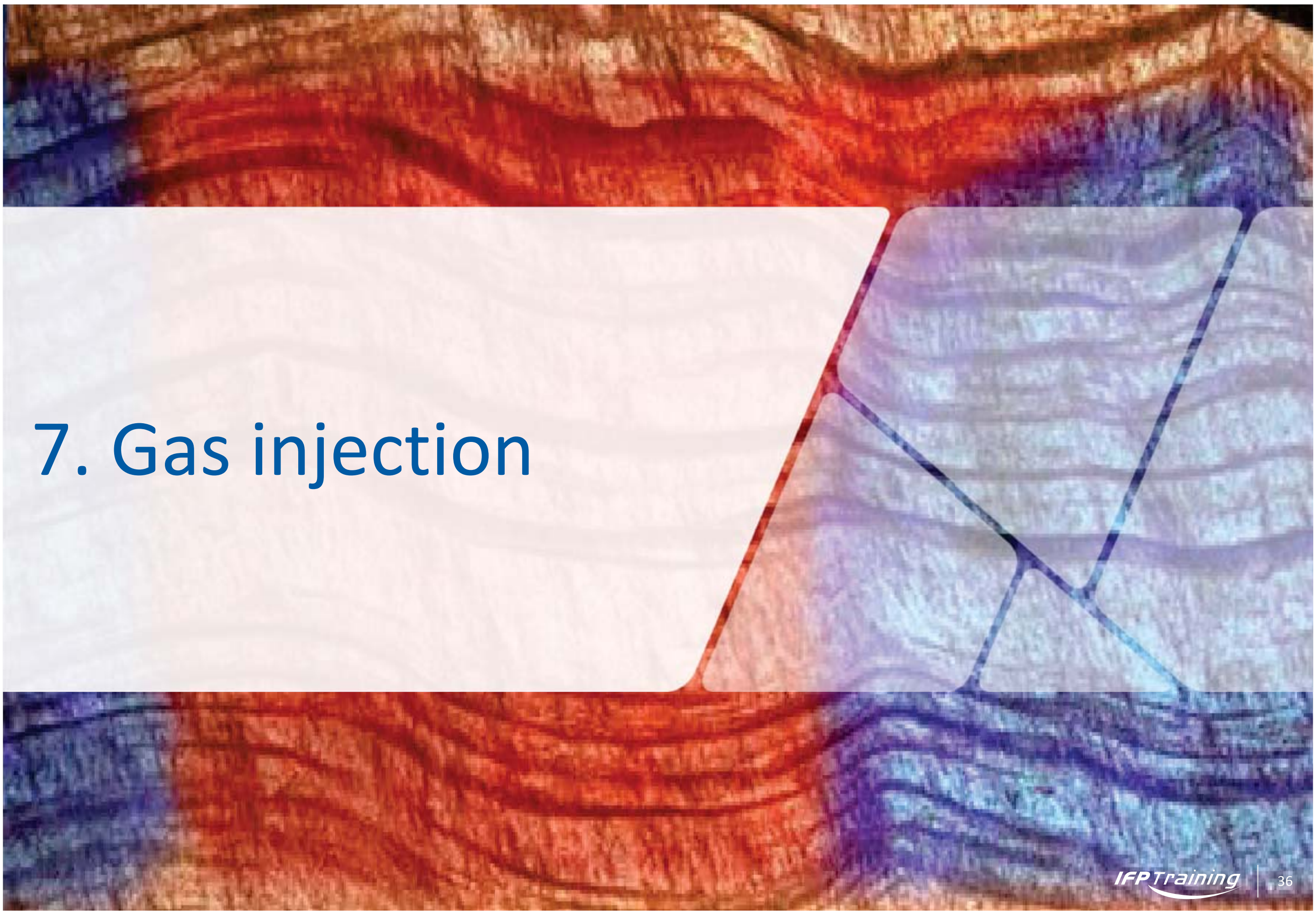


Practical considerations

- **Water sources**
  - Fresh surface water
  - Offshore: sea water
  - Water from a different reservoir (above, below…)
  - Produced water (PWRI)
- **Potential problems**
  - Compatibility with formation water ($BaSO_4$, $CaCO_3$ precipitates)
  - Interaction with reservoir rock (clays, rock weakening)
  - Water filtration
  - Biocides to prevent H_2S generation
  - Oxygen, bacteria removal
- **Injection of tracers (reservoir monitoring)**

Recovery factor

- **Parameters impacting recovery under water injection**
  - Residual oil saturation Sorw
  - Reservoir wettability
  - Permeability distribution, heterogeneities
  - Relative permeability & Water/Oil mobility ratio
  - Dips
  - Density contrast between oil and water
  - Kv/Kh anisotropy ratio
  - Vertical barriers and their extensions
  - Faults – Compartmentalization
  - Voidage replacement rate
  - …



Gas injection

- Gas injection is less often implemented, especially because of gas availability, cost of facilities, and gas market value
- Residual oil saturation to gas S_{org} can reach very low values (~0.05) thus leading to high displacement efficiency
- Due to very low gas viscosity, mobility ratio M is systematically high (>>1) leading to low areal efficiency; gas injection can however be considered in the case of light oil, for which M does not get to high
- Very sensitive to permeability heterogeneities which are difficult to estimate at the beginning of development

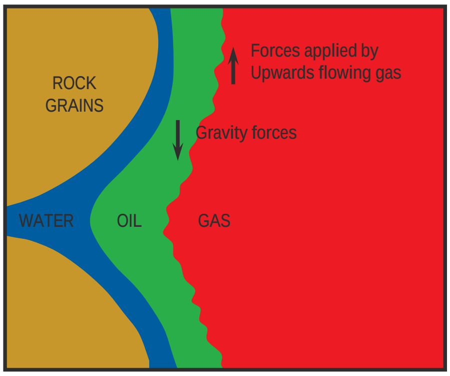
Gas injection

- Gas injection into a gas cap can lead to very good sweep efficiency
- In the case of good gas gravity displacement, recovery factor can be as high as 60-70%
- Gas injection can flood oil zone that were poorly swept by water (structurally higher, lower permeability)
- Oil swelling effect can occur within the reservoir, leading to a decrease in oil viscosity and better oil recovery

Gravity drainage

- When gas is injected at the crest of the structure, preferably in a gas cap, and if the dip angle is sufficient, the difference in gravity between gas and oil will promote segregation between the two fluids, this will allow the GOC to move downwards in gravity stable manner, despite the gas high mobility.

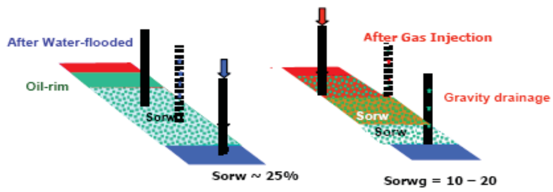
- Indeed, what happens is that the oil droplets will congregate in the presence of gas and will form a continuous phase which will keep on decanting slowly downwards to the producing wells.



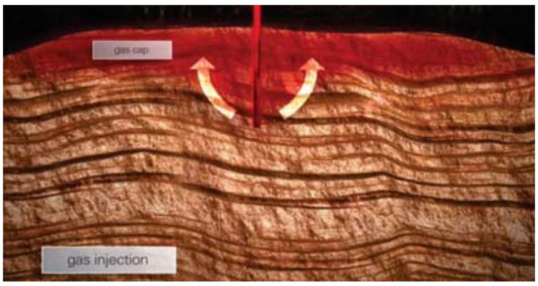
IFP Training

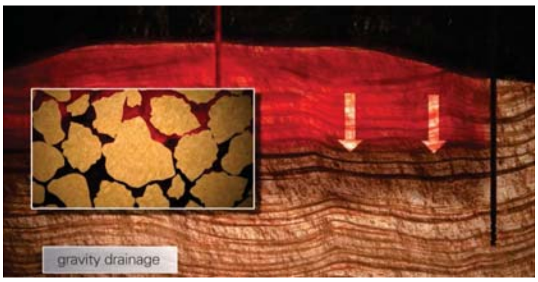
Gravity drainage

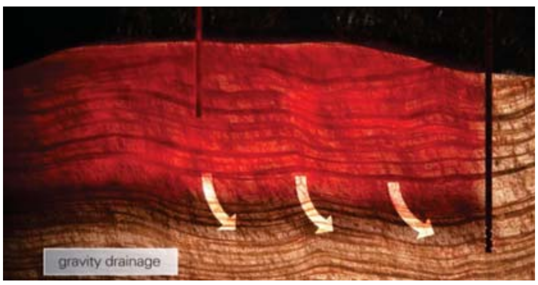
- An oil saturation of around 15-20% remains behind the gas front. This residual oil saturation will decrease with time.



- This is the most efficient IMMISCIBLE GAS DISPLACEMENT process.







BP Videos – YouTube
Exploiting science to increase oil recovery series

Practical considerations

- Injection gas is often made of hydrocarbon gas
- Due to low gas viscosity μ_g, injection wells have high injectivity
- Injection should be done in the gas zone for better injectivity
- Necessity of high wellhead injection pressure
- Gas treatment to remove H_2S, CO_2, O_2, H_2O (corrosion risk, hydrates formation)
- Gas sources: difficult to find
  - Great amount of gas needed
  - Produced gas reinjection (avoid flaring, only partial pressure support)
  - External source (gas market value)
- Due to gas price and facilities costs, gas injection projects are usually less economic than water injection projects
- Possibility to recover the injected gas later on
- Gas injection/cycling is very beneficial in gas condensate reservoirs

8. Summary – key points

Key points to keep in mind

Secondary Recovery

- Implemented when Primary Recovery is not efficient (typically when there is no water entry)
- Consists in assuring pressure maintenance and in improving sweep efficiency in the reservoir by injecting fluids, either water or gas
- Implies multiphase flow in the reservoir which has to be controlled in order to get good sweep efficiency
- Sweep efficiency is the RF in reservoir conditions for areas undergoing injection; it is divided into displacement, areal and vertical efficiency
- Sweep efficiency depends on multiple parameters among which mobility ratio: if $\mathrm{M} > 1$, mobility ratio is favorable, if $\mathrm{M} < 1$, it is unfavorable
- Sweep efficiency is typically in the range 25-60%

Key points to keep in mind

Injection characteristics

- Water is generally preferred to gas because
  - Sweeping efficiency is generally better
  - Availability is generally better
- To strictly maintain reservoir pressure, the injected volume should balance the produced volumes in reservoir conditions
- Injection pattern is of two types
  - Grouped flood in the case of high-dip reservoir or high permeability reservoir: central flood in case of gas injection, peripheral flood in case of water injection
  - Dispersed flood in the other case using patterns like 5-spot, 7-spot, etc.
  - In general, reservoir simulation is used to optimize well locations

Key points to keep in mind

Water injection

- **Water injection is the most commonly used Secondary Recovery process especially because of water availability**
- **Mobility ratio may be favorable, especially for light/medium oil and is, in any case, more favorable than for gas injection; however residual oil saturation may be quite high**
  - Density ratio is lower but high dip reservoir may favor gravity drainage and stabilization of injection front
- **Injectivity is much better in the water zone**
- **Good timing for injection start is critical: not too early, not too late**
- **Recovery factor can be as high as 50-60%**

Key points to keep in mind

Gas injection

- **Less used than water injection mainly because of gas availability and cost but may avoid flaring**
- **Displacement efficiency is better when compared to water**
- **Volumetric efficiency is lower when compared to water**
  - Systematically unfavorable mobility ratio (M>>1)
  - Very sensitive to permeability heterogeneities
  - High gravity contrast may favor gravity drainage and stabilize the injection front
  - Injection into a gas cap can lead to very efficient sweeping
- **In the case of good gas gravity displacement, RF can be as high as 60-70%**
- **Immiscible gas displacement may convert to gas miscible displacement which leads to higher recovery factors (cf. Enhanced Oil Recovery)**

Key points to keep in mind

Recovery factors

- **Natural drainage mechanisms for oil reservoirs**
  - Monophasic expansion — RF few %
  - Solution gas drive — RF 10-25 %
  - Gas cap drive — RF 25-40 %
  - Natural water drive — RF 40-60 %
  - Compaction drive — RF 0-20 %

- **Pressure maintenance in oil reservoirs**
  - Water injection — RF up to 50-60%
  - Gas injection (gravity displacement) — RF up to 60-70% (see EOR)

Fundamentals of Reservoir Engineering – Drive mechanisms Tertiary recovery

Week#2

PTTEP Algeria

November 2016

IFP Training

Outline

1. Introduction
2. Miscible gas injection
3. Chemical processes
4. Thermal processes

1. Introduction

Improved Oil Recovery

- **Conventional methods**
  - Natural energy — «Primary»
  - Water injection & immiscible gas inj — «Secondary»

- **Unconventional methods**
  - E.O.R. — Miscible gas injection, Chemical processes, Thermal processes — «Tertiary»
  - Other technologies: — Complex & intelligent wells; Improved reservoir management

Sweep efficiency

- **The overall displacement efficiency may be expressed as:**

$$E = E_v \times E_m \quad \text{with} \quad E_v = E_a \times E_z$$

- E_v is the volumetric sweep efficiency. It can be high for liquids displacing oil (up to 80 %) and low for gases displacing oil (as low as a few %)
- The term E_m accounts for the trapping of oil by capillary forces in the pores invaded by the displacing fluid, and is also known as the microscopic displacement efficiency. It is also noted as E_d
- E_m will be in the order of 0.6-0.7 for water displacing oil and as high as 0.9-0.95 for gas displacing oil

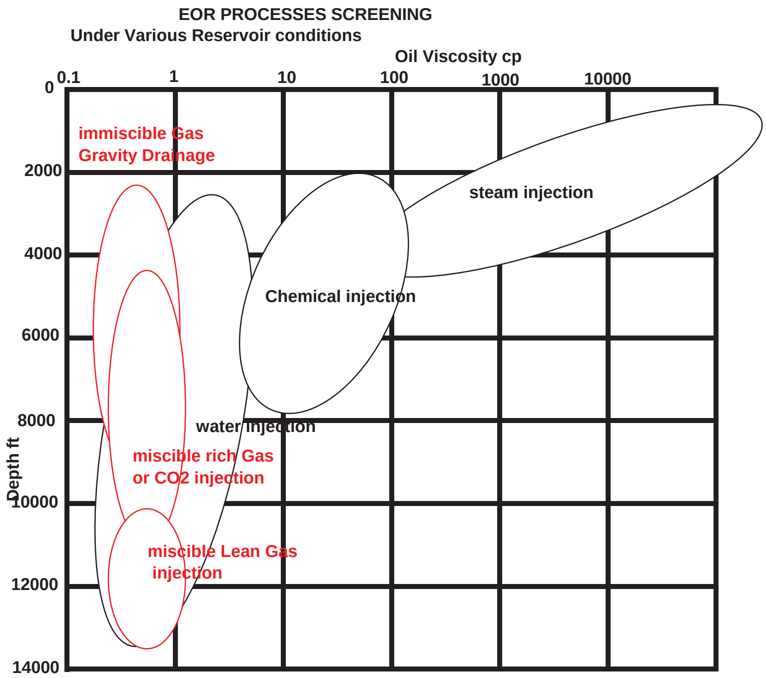
EOR principles

- **Principles**
  - **Improvement of displacement efficiency E_d**
    - By decreasing S_{or} (decrease of interfacial tension)
      miscible flood
      chemical flood-surfactants
  - **Improvement of volumetric sweep efficiency E_A x E_v**
    - By increasing μ_w
      chemical flood – polymers
    - By reducing μ_o
      thermal flood

Pilots and studies

- **Since EOR processes are often very expensive, economic studies are very important**
- **Pilot trials for some EOR processes are a must before going full field**
- **Project design should include detailed simulation studies (1D, 2D, 3D)**
  - Numerical simulation of lab results
  - Mechanistic cross sections
  - Full field models
- **Specific sophisticated experimental studies are needed**
  - SCAL (wettability, Kr’s, Pc)
  - Waterflood and gasflood at reservoir conditions
  - Advanced PVT experiments to match EOS (to predict exchanges)
  - Etc.

Introduction
Scheme of screening for EOR methods



2. Miscible gas injection

Generalities

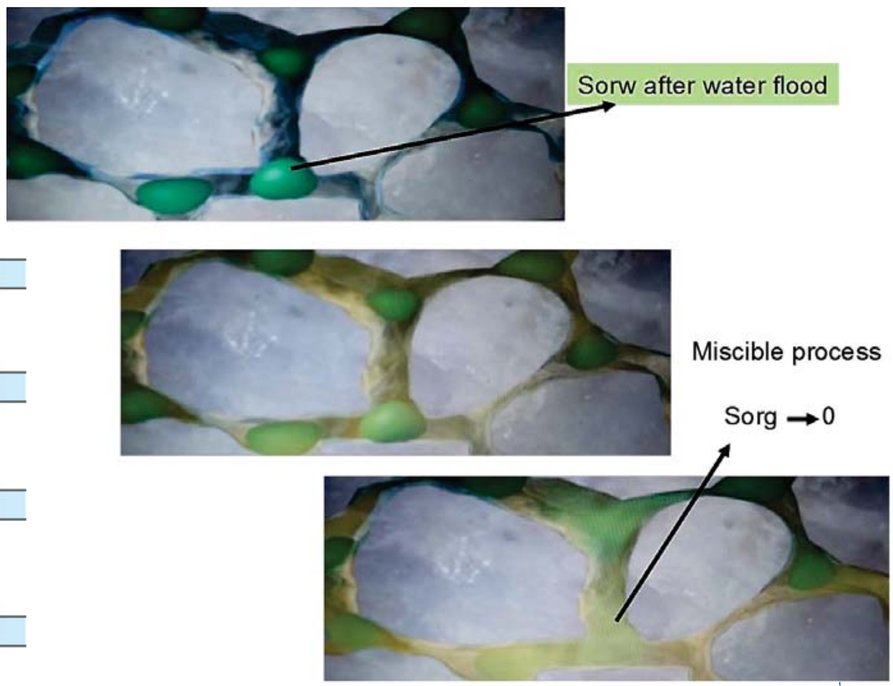
- **Definition**
  - Two fluids are miscible if they can mix in all proportions and form a single homogeneous phase
  - Minimum miscibility pressure is the lowest pressure at which miscibility (direct or multiple contact) can be achieved, at given temperature and composition

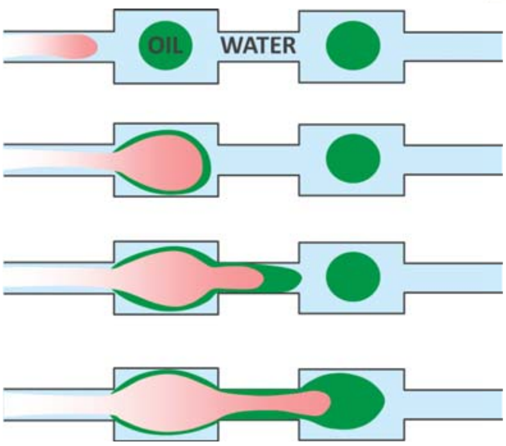
- **Miscible gas injection**
  - No more interfacial tension: S_{org} tends to zero
  - Direct (first contact) miscibility: rare
  - Multiple contact (dynamic) miscibility
    - Vaporizing gas drive
    - Condensing gas drive

- **Water Alternating Gas or Foam flooding**
  - To improve miscible gas flooding stability

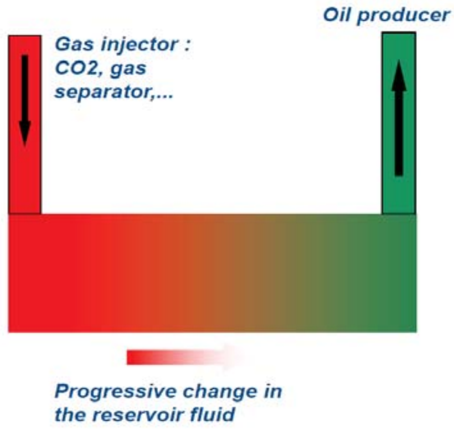
Principles of miscible gas injection

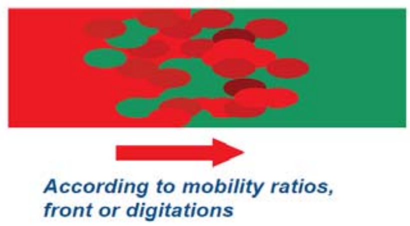
- **Pore-level mechanism: microscopic efficiency**
  - Mobilization of oil that was trapped behind water front: **oil swelling**
  - Formation of gas-oil interfaces → **reduction of IFT** → S_{org} **tends to zero**





Gas injection: Main mechanisms



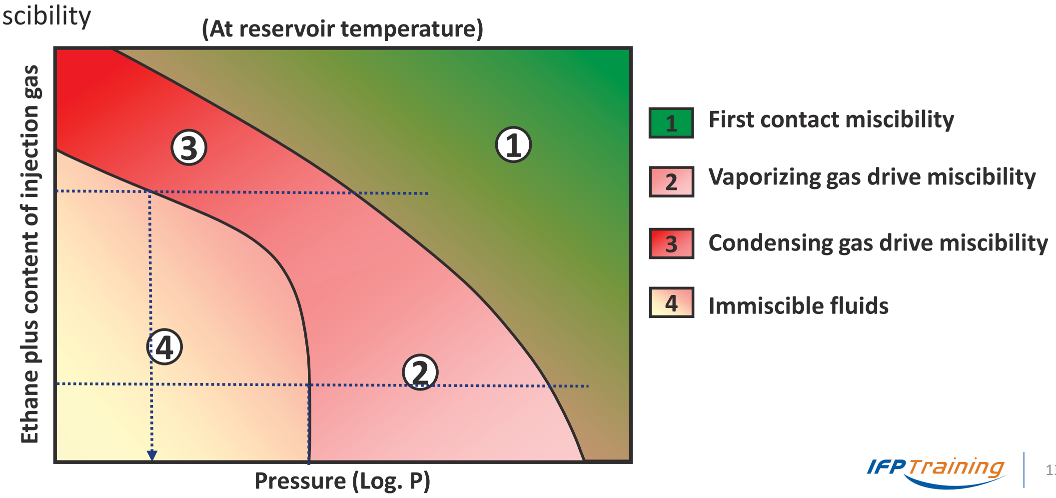


- According to gas and oil composition and also reservoir pressure and temperature:
  1. Miscibility is possible: obtention of a single fluid
  2. No miscibility – two phases: sweeping efficiency depends on mobility ratio.

Miscible gas injection

Gas-Oil miscibility

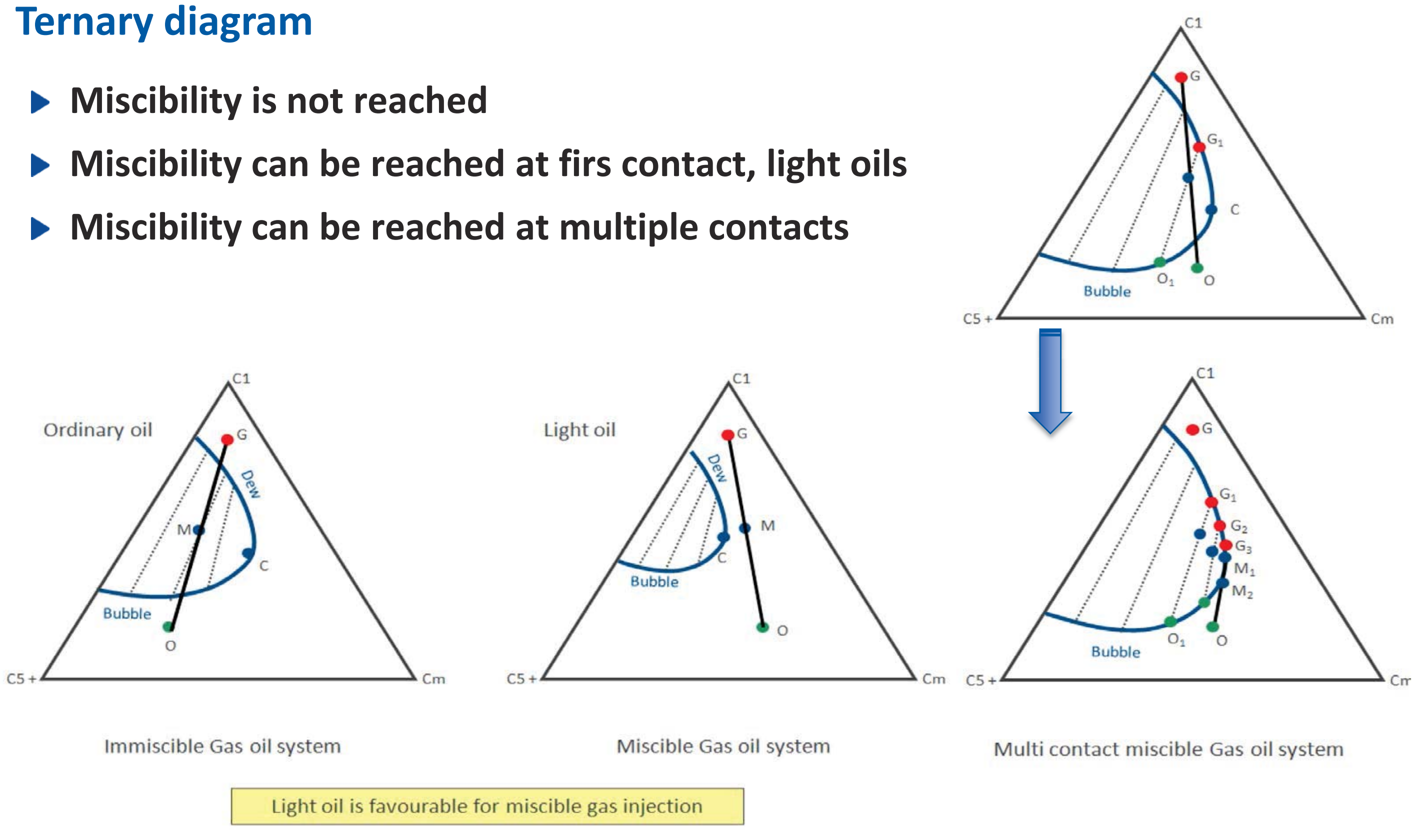
- Miscibility depends on pressure and temperature
- Miscibility is rarely obtained directly: multiple-contact miscibility (also called dynamic miscibility)
- Multiple-contact miscibility: the injected gas and the in-situ oil exchange components until miscibility between the two phases is reached
- Two-types of multiple-contact miscibility:
  - Vaporizing gas miscibility
  - Condensing gas miscibility



Miscibility

Ternary diagram

- Miscibility is not reached
- Miscibility can be reached at firs contact, light oils
- Miscibility can be reached at multiple contacts



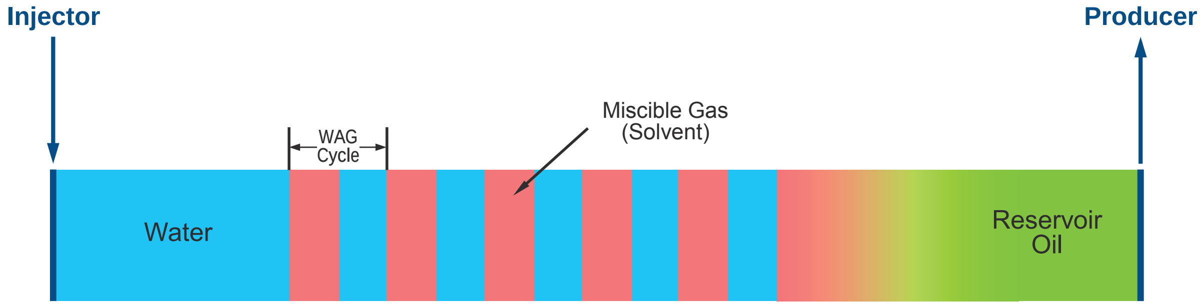
CO_2 injection

- Miscibility with oil may be achieved at lower pressures than those required by hydrocarbon gas
- Moreover, high solubility of CO_2 in oil results in
  - A large reduction in oil viscosity which in turn makes a significant improvement of oil mobility in the reservoir
  - Swelling of the oil by some 10 to 20%, depending on its type and saturation pressure
- Another interesting characteristic of CO_2 is the density: even in gaseous state, its density is comparable to oil density at reservoir conditions

Miscible gas injection

Improving gas injection processes

- **WAG – Water Alternate Gas**
  - Alternates gas injection with water injection
  - Allows to control the stability of the front by increasing the viscosity of the combined flood front thus improving the volumetric sweeping efficiency
  - Improvement of RF may remain modest

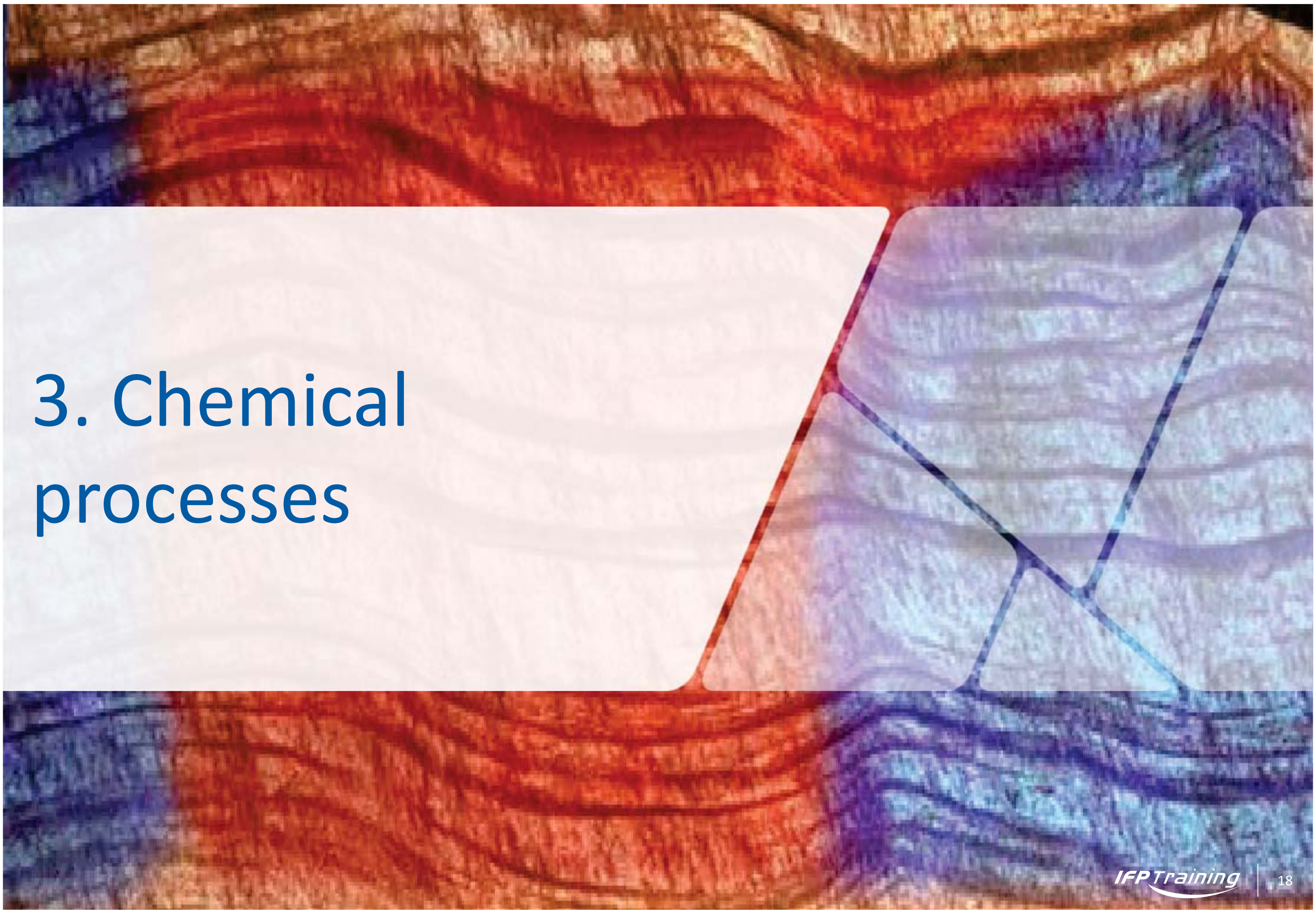


- **Foam flooding**
  - May be obtained by co-injecting gas and a surfactant solution
  - Allows to control the stability of the front but foam stability in presence of oil is still to be optimized

Key points to keep in mind

Miscible gas injection

- **Residual oil saturation following miscible gas flooding tends towards zero**
  - Theoretical displacement efficiency is 100%!!!
- **Oil swelling helps to mobilize oil blobs isolated after water flooding**
- **But volumetric efficiency of miscible gas flooding may remain low**
  - Improve flooding stability by injecting water (WAG) or foam (foam flooding)
- **Direct miscibility may be difficult to achieve:**
  - Multiple-contact miscibility for hydrocarbons with exchange of components between gas and oil
  - Easier to achieve with CO_2 (lower Minimal Miscibility Pressure)



3. Chemical processes

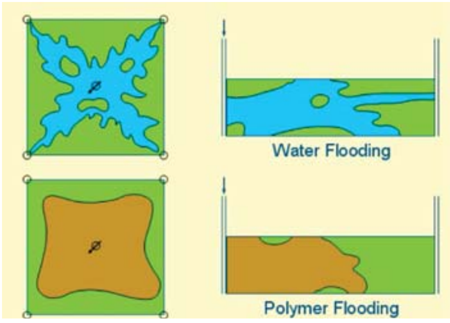
Polymers and surfactants

- Chemical recovery methods have the following objectives
- Polymers: to improve the volumetric sweep efficiency, by reducing the mobility ratio between injected and in-place fluids
- Surfactants: to eliminate or reduce the interfacial tension between oil and water and thus improve displacement efficiency, i.e. maximize E_d
- To act on both phenomena simultaneously

Injection of polymer solutions

- **Polymer flooding is the most commonly used chemical enhancement process**

- **Displacing fluid is viscosified with soluble polymers, which reduces the mobility ratio and leads to a better volumetric sweep efficiency**



- **Recovery factor may be increased by a modest amount**

- **Polymer concentrations are between 100 to 1000 ppm and treatment requires the injection of 15 to 30% PV followed by water injection**

Chemical processes
Surfactant flooding

- **Surfactant performance is optimal under a narrow range of conditions**
  - Difficult at high temperature and high salinity
  - Preferably sandstones (some surfactant like alkali may cause precipitation in carbonates reservoir resulting in pores plugging)
  - surfactants may have low viscosity leading to poor sweeping efficiency

- **However, surfactant flooding has high potential in terms of oil recovery**
  - Surfactant flooding is generally used with the injection of other chemicals which reduce surfactant losses due to adsorption on the reservoir rock
  - The latest technology is a combination of Alkaline, Surfactant and Polymer (ASP flood): nowadays, the ASP is the recommended process

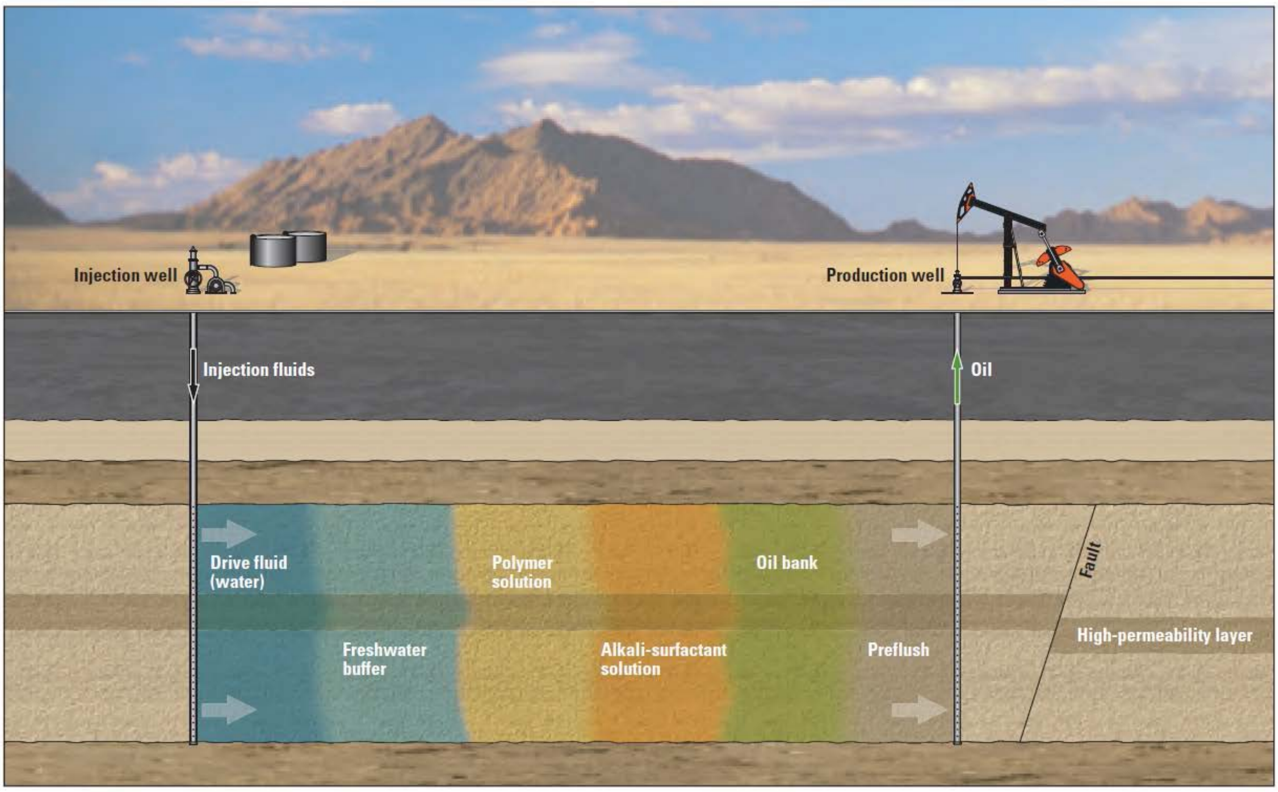
Chemical processes

ASP flooding

- **Principles: combining the best technics**
  - Injection of alkali (typically sodium hydroxide) which reacts with acidic oil components to create in-situ surfactant (petroleum soap)
  - Simultaneous injection of synthetic surfactant to reduce IFT
  - Injection of a water-soluble polymer both with the alkali-surfactant mixture and as a slug following the chemicals injection in order to increase viscosity and control the flooding front thus improving sweeping efficiency (mobility buffer)
  - Injection of water to drive chemicals and oil bank towards the producers

- **Performances**
  - ASP can theoretically lead to very high recovery factor, up to 90% as shown in laboratory and field pilot
  - ASP is not recommended for carbonate reservoirs (possible reaction of alkali with calcium ions to form precipitates)

ASP flooding



Key points to keep in mind

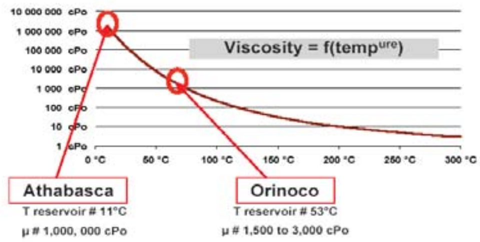
Chemical processes

- **Chemical processes objectives may be quite different**
  - Polymer flooding: increase viscosity of displacing fluid in order to stabilize the front and increase volumetric efficiency
  - Surfactant flooding: decrease IFT in order to decrease residual oil saturation and increase microscopic efficiency
- **New processes designed to get advantage of both: ASP**
  - Alkali-Surfactant-Polymer flooding combine both Polymer flooding and Surfactant flooding to reach very high RF, up to 90%
- **Operational conditions**
  - Proper design of the process may be difficult
  - Temperature and salinity may decrease severely the process efficiency
  - Alkali and ASP flooding not to be used with carbonates reservoir as they may cause precipitation and pore plugging

4. Thermal processes

Thermal methods

- **Objectives**
  - To get a lower oil viscosity and a higher mobility
  - To improve well productivity
  - To improve the final recovery factor
- **Different Methods**
  - Steam flood
  - In situ combustion
- **These methods are used with viscous oil**



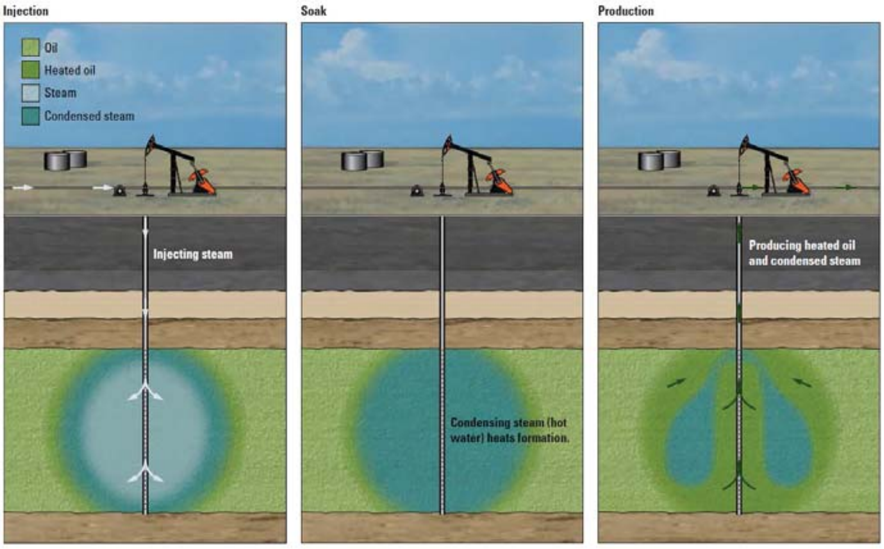
- **Steam flood**
  - Steam generated at surface is injected into the reservoir through specially distributed injection wells.
  - Different ways of implementation: Cyclic Steam Injection (Huff and Puff), Continuous Steam Flood, Steam Assisted Gravity Drainage

Steam injection
Several methods

- **Cyclic steam injection (huff and puff)**
  - Injection of steam into one well (10 days - 1 month)
  - Soaking period: well shut-in (1 - 10 days)
  - Production from stimulated well (3 months - 1 year)
  - Stimulates production, accelerated depletion
  - Not a recovery technique except specific cases
- **Steam drive**
  - Continuous injection of steam into injectors
  - Oil pushed to producers
  - Recovery technique
  - Often applied after depletion by several “huff and puff” cycles
- **SAGD process**
  - Steam assisted gravity drainage
  - Continuous injection of steam into horizontal wells
  - Oil produced by gravity in horizontal wells located below the injectors

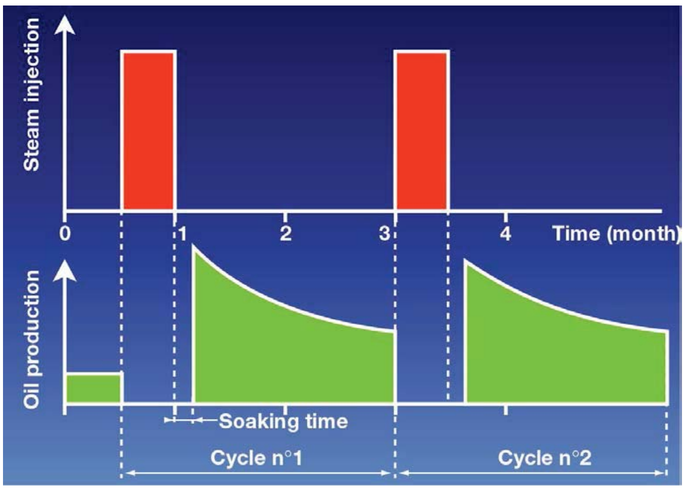
Cyclic steam stimulation

- High pressure steam injected during several weeks --> heating of the oil, reduction of viscosity
- Soak period during several weeks
- Pumping of the oil up to the surface
- When production declines: switch back to injection



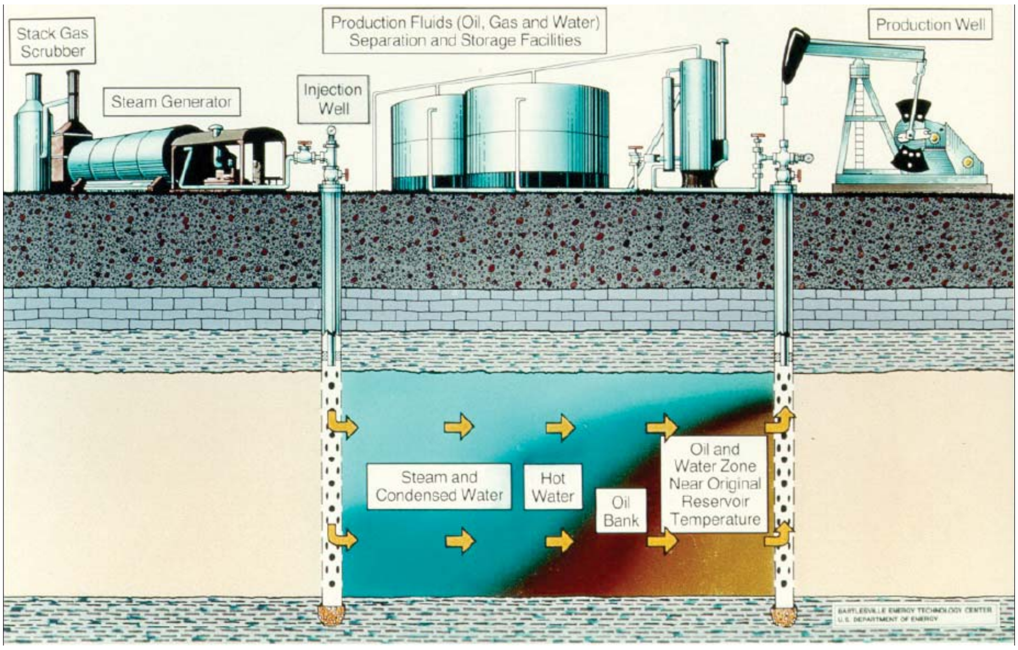
Cyclic Steam Stimulation

- Proven technology
- Examples:
  - Canada: Cold Lake, Wolf Lake, Primrose
  - Venezuela: Maracaibo area
  - California: Kern River
- Operating costs: 4-5 US$/bbl
- Drawbacks:
  - Only stimulation around wellbore
  - Limited recovery factor (15-20%)
  - Energy consumption and GHG emission



Continuos steamflood

- High-temperature steam is continuously injected into the reservoir
- As the steam loses heat to the formation, it condenses into hot water
- Steam and hot water drive to move the oil to production wells



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Continuos steamflood

- As the formation heats, oil recovery is increased by:
  - Viscosity reduction, increasing oil mobility
  - Expansion or swelling of the oil
  - Vaporisation of lighter fractions of the oil. The fractions move ahead into the cooler formation where they condense and form a solvent or miscible bank
  - Condensed water forms a waterflood
- Up to 50% recovery can be achieved with a oil/steam ratio (OSR) of 0.2
- Examples: Maracaibo (Venezuela), California (Kern River), Indonesia (Duri), Alberta (Peace River)
- Often used after initial CSS phase (to stimulate well neighbourhoods)

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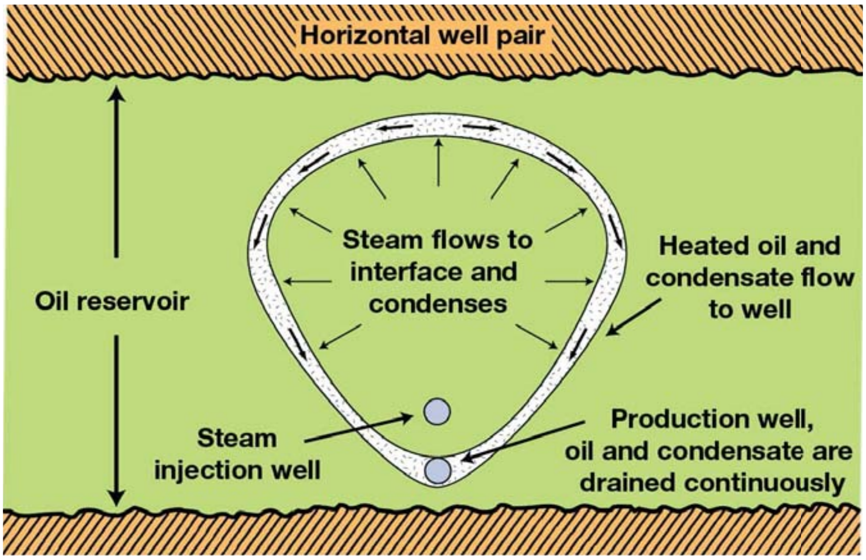
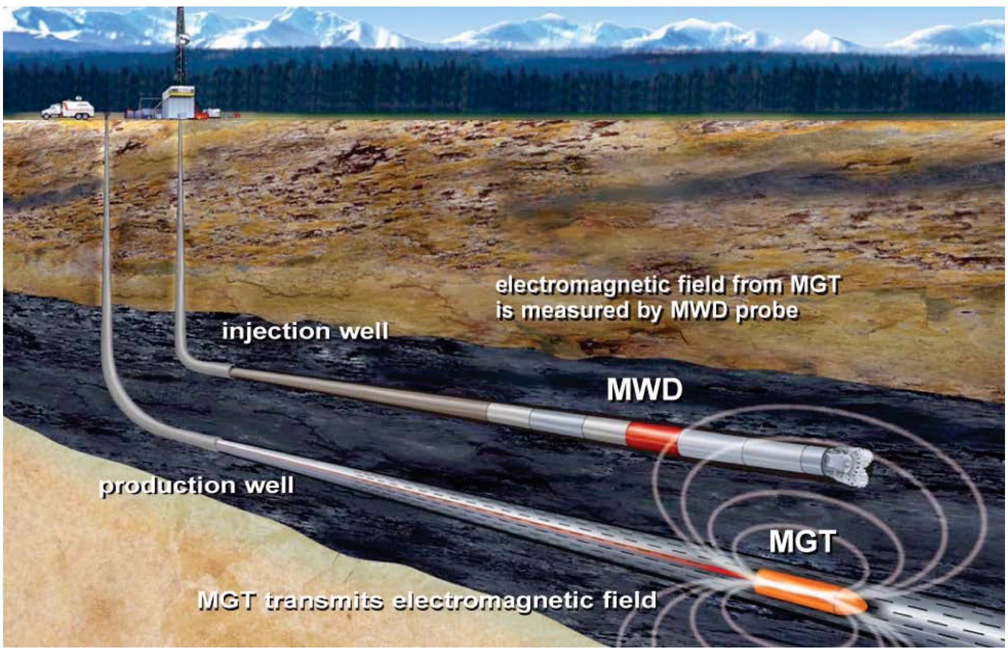
Steam Assisted Gravity Drainage

- In the SAGD process, two parallel horizontal oil wells are drilled in the formation, one about 4 to 6 metres above the other. The upper well injects steam, possibly mixed with solvents, and the lower one collects the heated crude oil that flows out of the formation, along with water from the condensation of injected steam



Steam Assisted Gravity Drainage

- A view of the drilling of one pair of wells



Steam injection
Heat losses

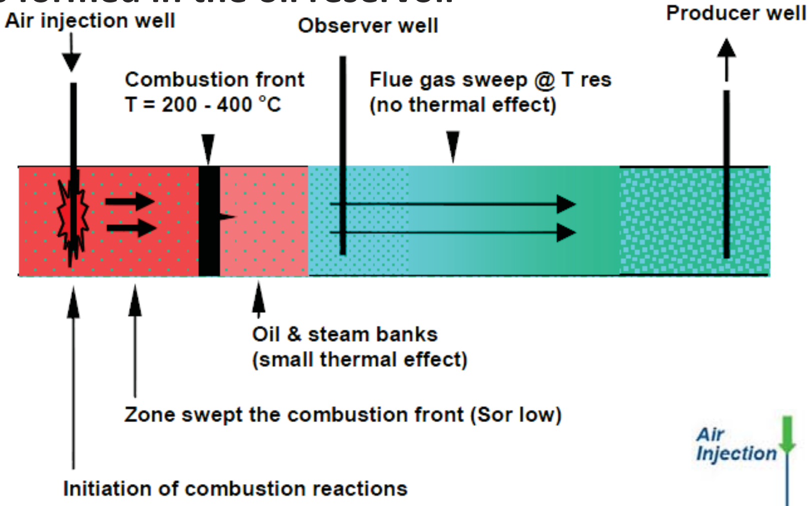
- **Heat is carried some distance by the displacing fluid to its final destination in the reservoir**
- **Heat loss is a critical factor for recovery processes by hot fluid injection**
  - Heat loss from the reservoir to the surrounding formations: the extent of the steam condensation zone is reduced and so is the thermal efficiency of the process
  - The consequence is that it is not applicable to very thin beds or to those reservoirs in which the spacing between injector and producer is large
  - Heat loss from the well: a further cause of heat loss occurs in the passage of the hot fluids in the injection well from surface to the injection zone.
- **It should be mentioned that steam generation is intensive in terms of**
  - Energy consumption and combustion of hydrocarbons
  - Environmental impact due to CO_2 produced in the above combustion
  - Use of fresh water, which can be scarce, treatment and re-cycling of produced water
- **The rewards are that the steam injection can yield high recovery factors**

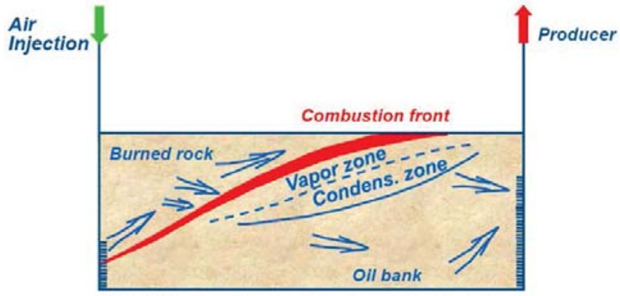
In-situ combustion

- **Oil is ignited around well bore**
- **Burning front sustained by continuous injection of air**
- **A small portion of the oil is burned**
- **The heat generated**
  - Reduces oil viscosity
  - Produces miscible fluids
  - Increases sweep efficiency
  - Reduces oil saturation
- **Continuous air injection develops efficient gas drive mechanisms**

In-situ Combustion: Air injection

- **Schematic representation of in-situ combustion process and the various zones as formed in the oil reservoir**





Key points to keep in mind

Thermal processes

- **Main objective of thermal processes is to decrease oil viscosity in order to increase oil mobility**
- **Mandatory in some cases, especially with heavy oils that may not flood in local normal conditions (typically in Canada)**
- **Several processes may be used**
  - Cyclic steam injection
  - Steam flooding
  - SAGD
  - In-situ combustion
- **Main drawbacks of thermal processes: economics**
  - Heat losses
  - Energy to produce steam
  - Water: treatment, recycling

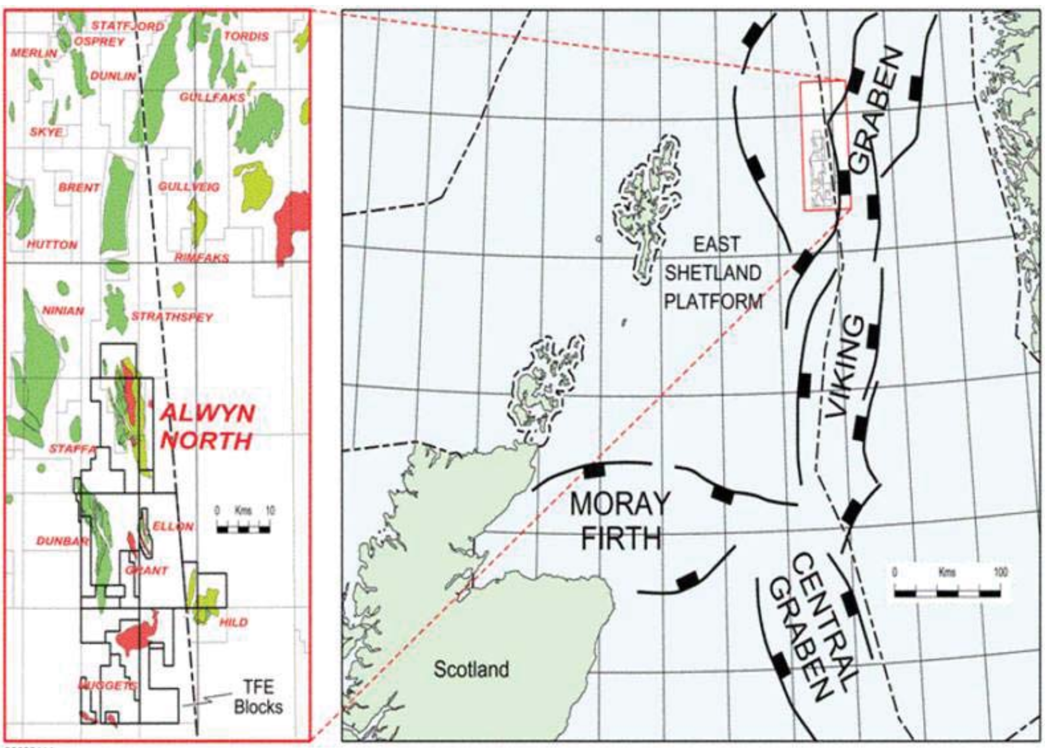
Fundamentals of Reservoir Engineering – Case study Field Development

Week#2

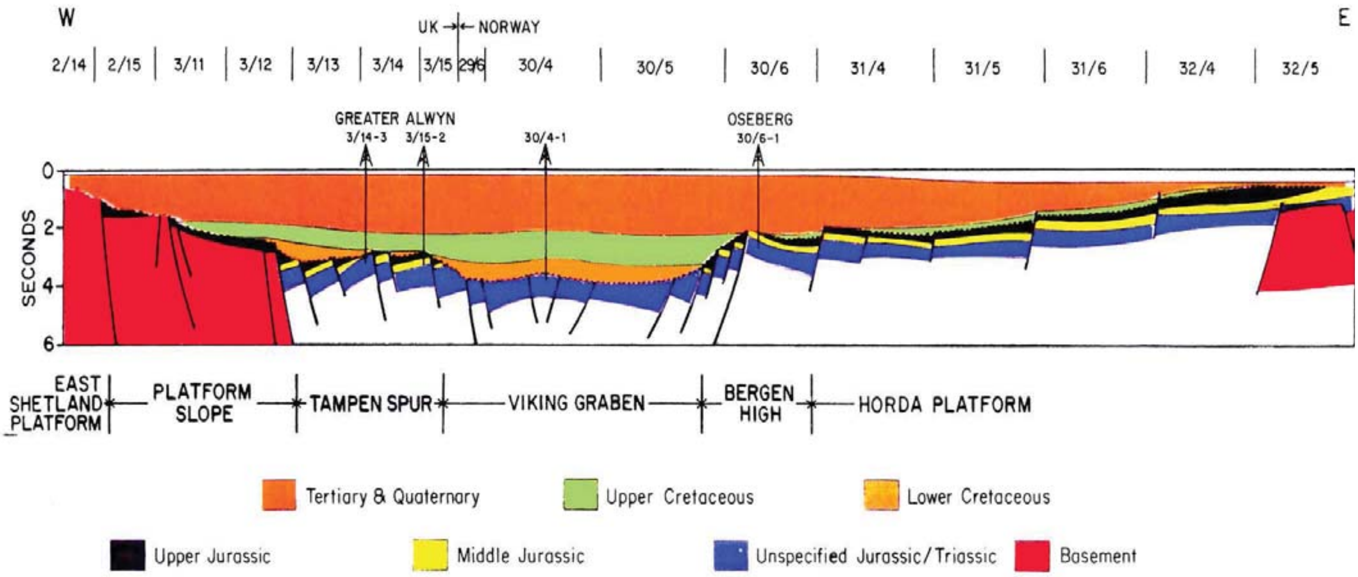
PTTEP Algeria

November 2016

North Sea Area: Alwyn location map



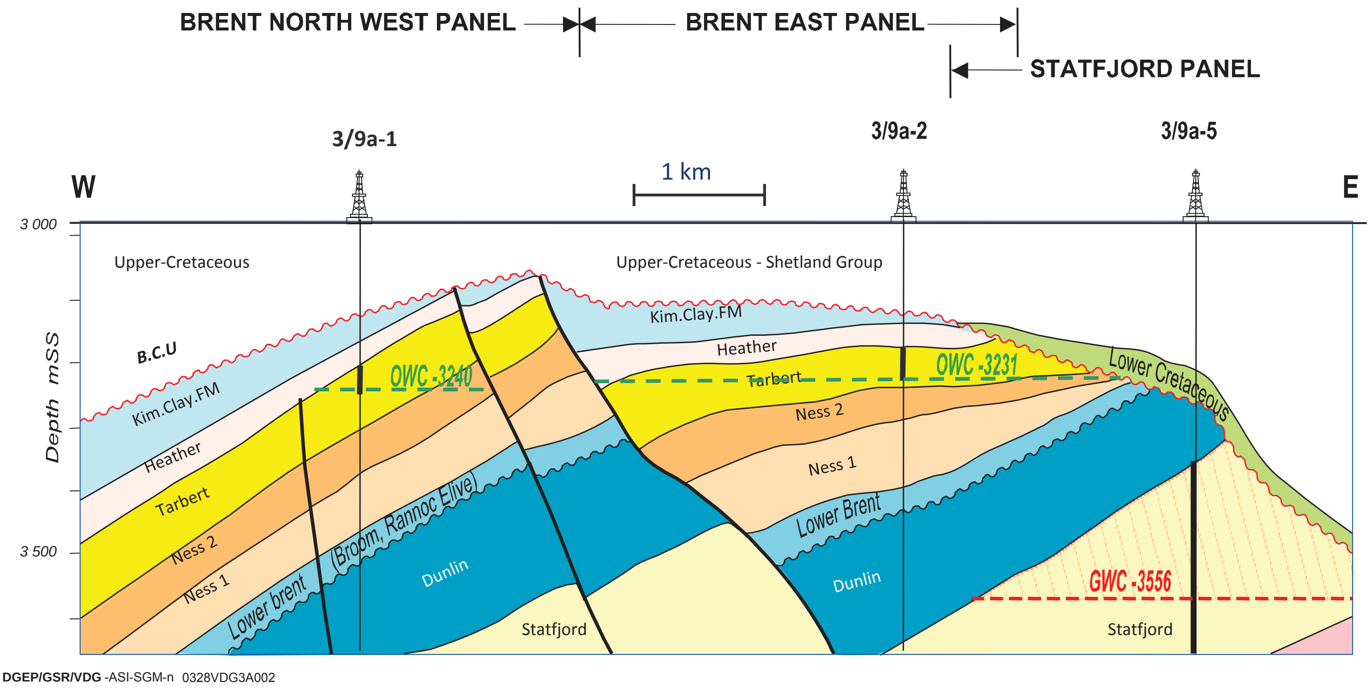
North sea structural cross section



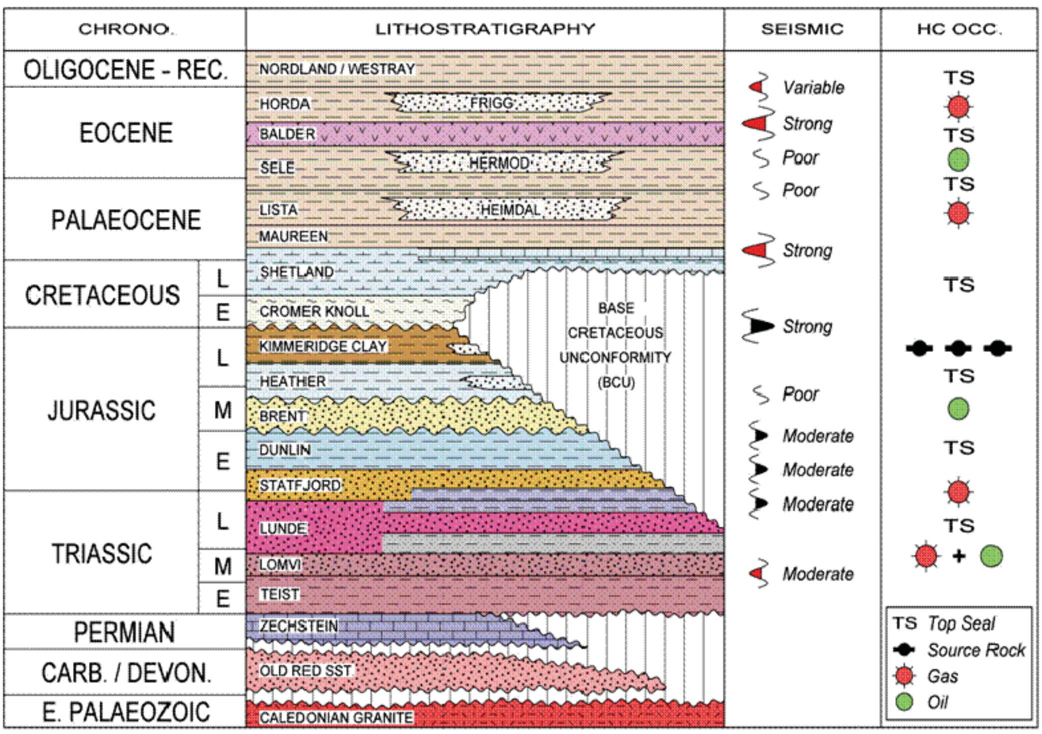
Exploration and appraisal

- **Petroleum system**
  - Source rock :
    - Kimmeridge clay (Jurassic)
  - Reservoir rocks :
    - Brent & Statfjord (Jurassic)
    - Lunde & Lomvi (Trias)
  - Seal rocks :
    - Heather & Dunlin shales (Jurassic)
    - Upper Trias
- **Three main reservoirs**
  - Brent (oil) discovered in 1975
  - Statfjord (gas condensate) discovered in 1979
  - Trias (Gas condensate) discovered in 1995
- **Seven wells drilled before initial FDP**
  - Six wells drilled in Brent formation
  - One well drilled in Statfjord formation

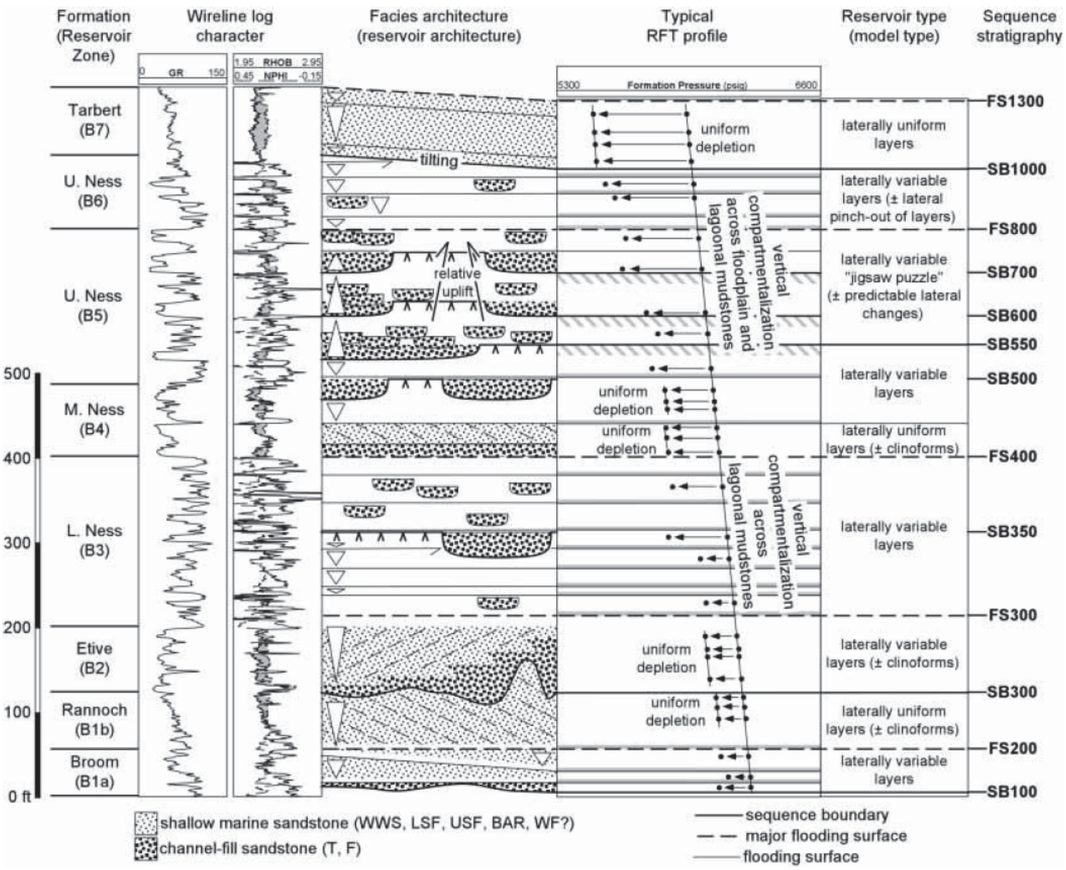
Brent geological cross section



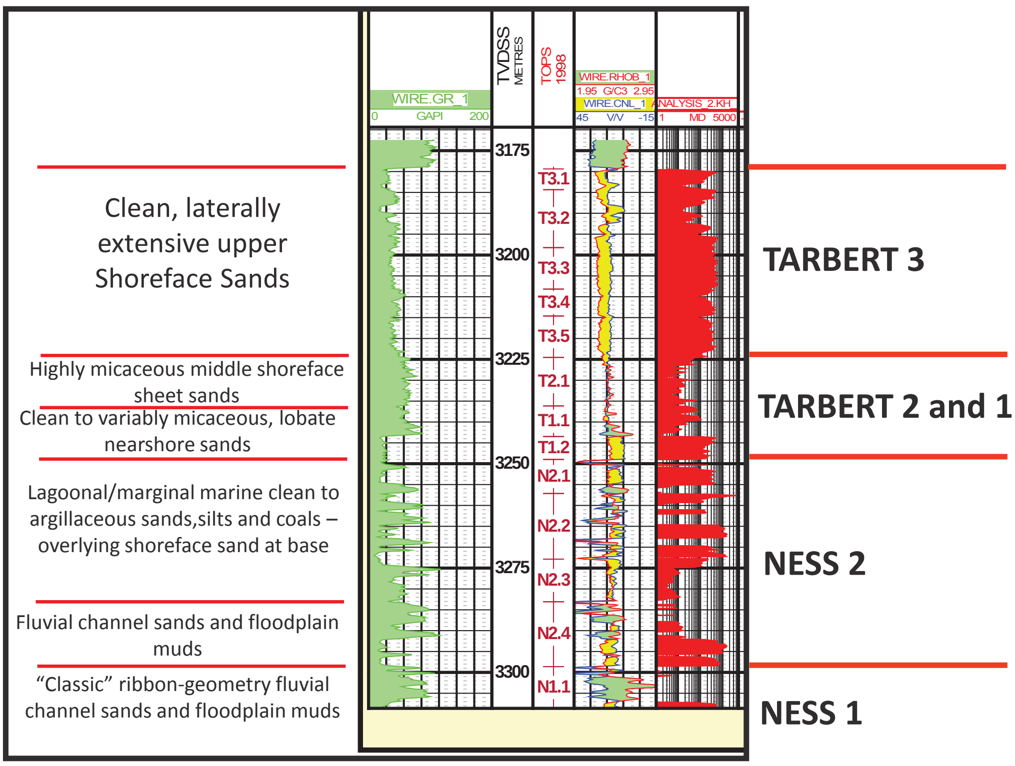
Regional Stratigraphy & HC Occurrences



Sequence stratigraphy and facies architecture of Brent

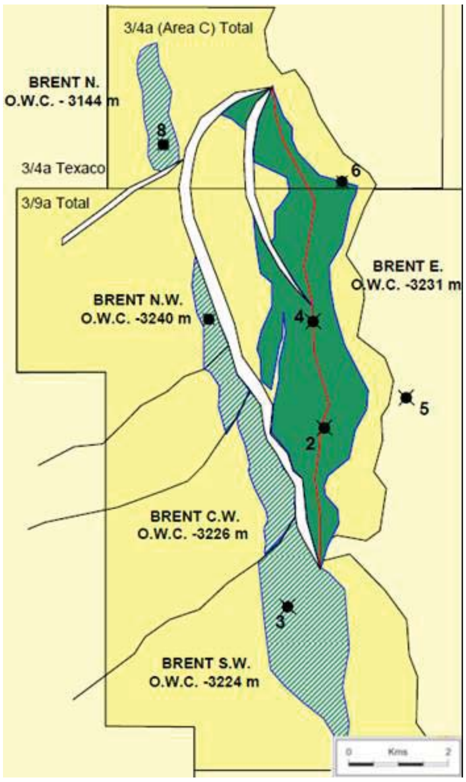


Brent Geological well section

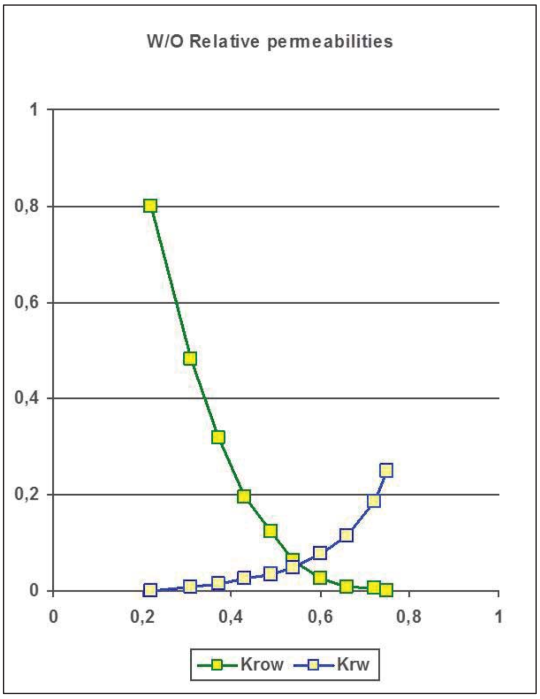


AN Brent key data & exploration wells

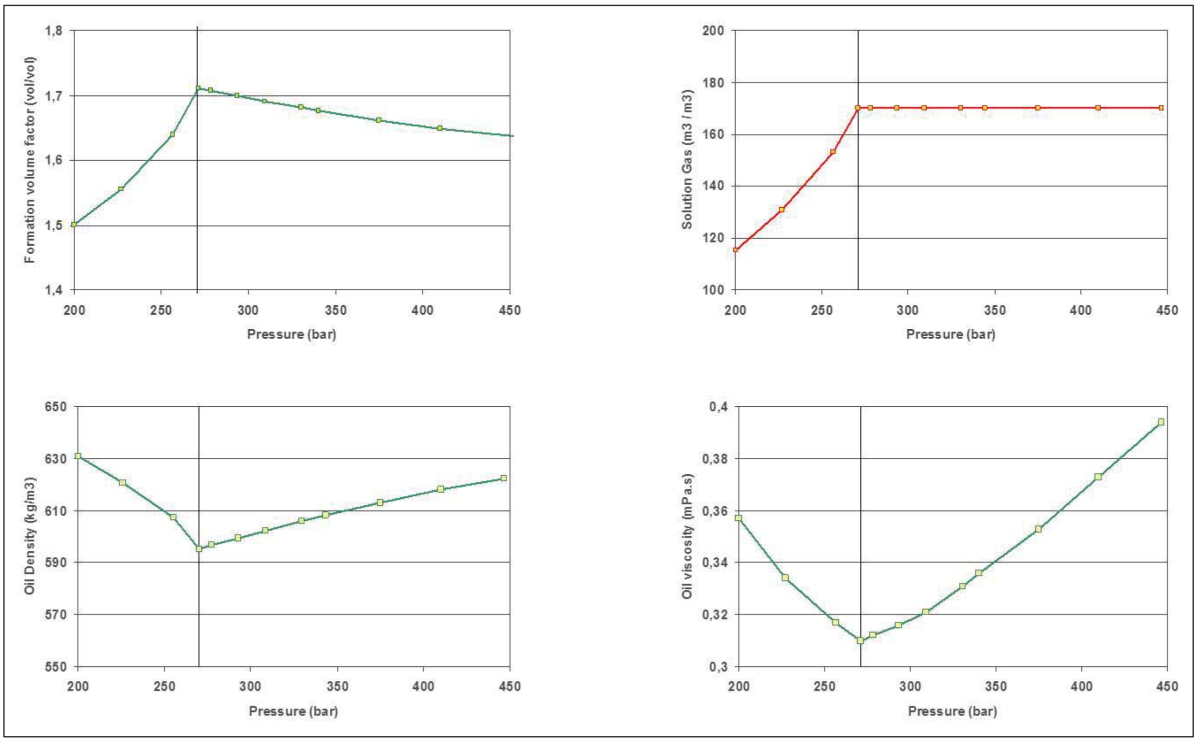
- **Oil bearing middle Jurassic Tarbert and Ness formations (Depth ~3200 m TVDSS)**
- **Sequence of sands/silts/shales deposited in deltaic and shoreface environments. Tilted fault blocks dipping to west**
- **Fluids :**
  - P initial = 446 bar
  - T initial = 110 °C
  - P sat = 257 bar
  - GOR = 196 v/v
  - Bo = 1.64



Relative permeability curves



Oil properties



Production constraints

- The minimum bottom hole flowing pressure (BHFP) is 260 bar.
- Drainage radius for vertical wells is about 400 m.
- Due to surface facilities on platforms, the maximum allowable GOR is 1500 m3/m3 and the maximum allowable water cut is 90 %. The minimum economical rate for any well is 100 Sm3/d of oil.
- Only to estimate the productivity index, consider a skin of 5.
- Consider a skin of -4 induced by thermal fractures due to the low temperature of the sea water.

- The annual production plateau should be around 15% of EUR

The study…

The goal is to propose a development plan for

Alwyn North – Brent East Panel

Aspects to investigate:

- **Using material balance, the different drive mechanisms should be investigated in order to estimate the oil recovery. Primary production as well as water injection must be investigated (material balance calculation above Psat). In order to calculate the Material Balance, use average values of ϕ, Swi and Sor.**
- **Different production schemes should be defined:**
  - Natural depletion,
  - Water injection.

  Each scenario must be reported with all relevant information: recovery factor, number of wells, production plateau…

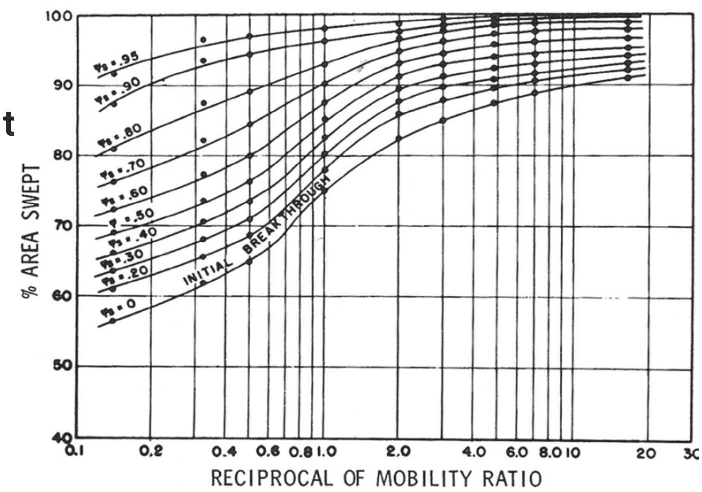
Plateau rate and initial number of wells

- **Areal efficiency (Ea):**

Areal Sweep efficiency correlation (Dyes et al. Abacuses for 5-spot, direct and staggered line-drive)

Values depend on pattern type, fw and end point mobility ratio

- **Result was obtained for a staggered pat**
- **Effect of M on oil production for**
- **a staggered pattern d/a=1:**



Fundamentals of Reservoir Simulation

Week#2

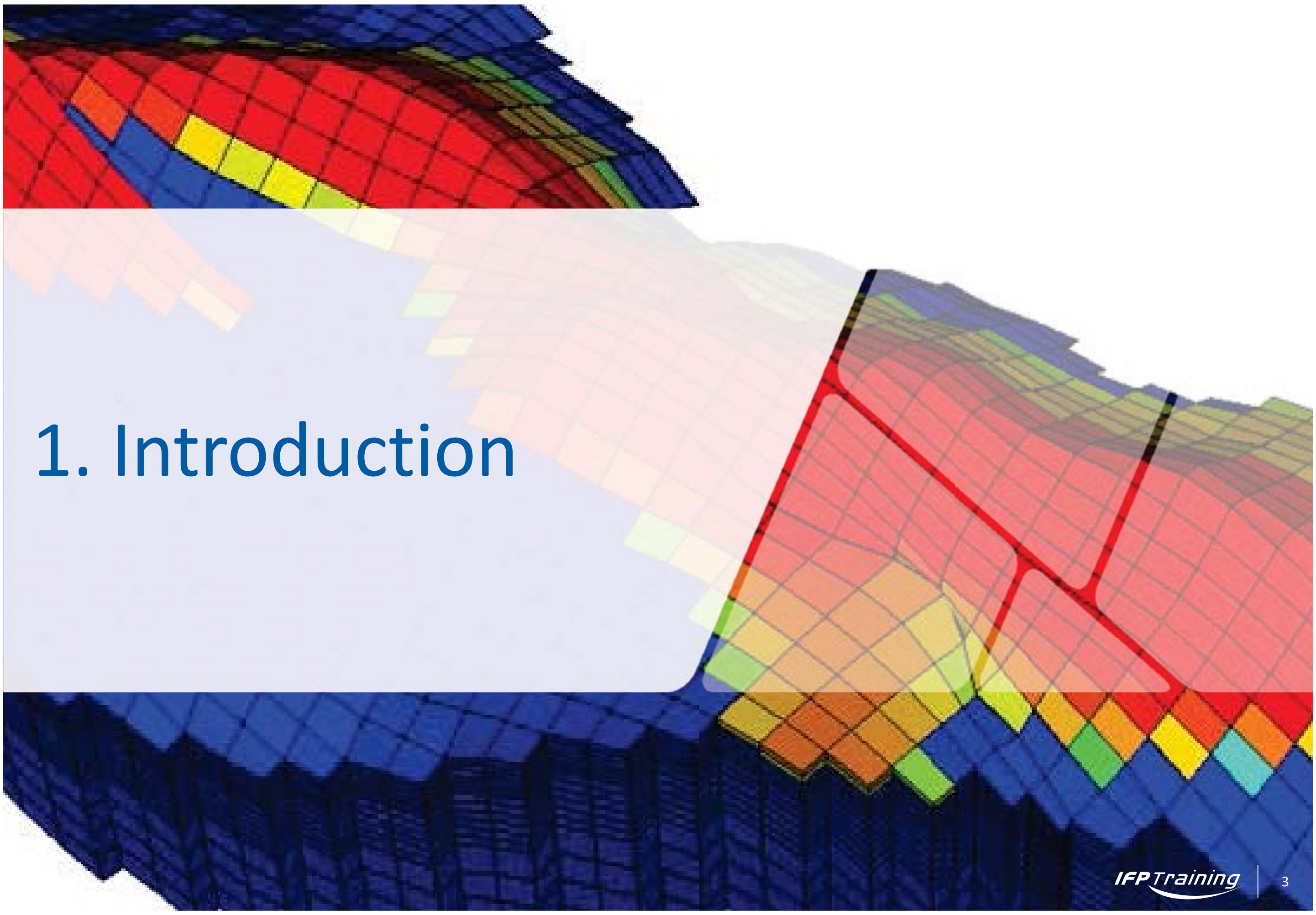
PTTEP Algeria

November 2016

IFP Training

Outline

1. Introduction
2. Reservoir simulation model
3. General workflow
4. Case study



1. Introduction

Introduction

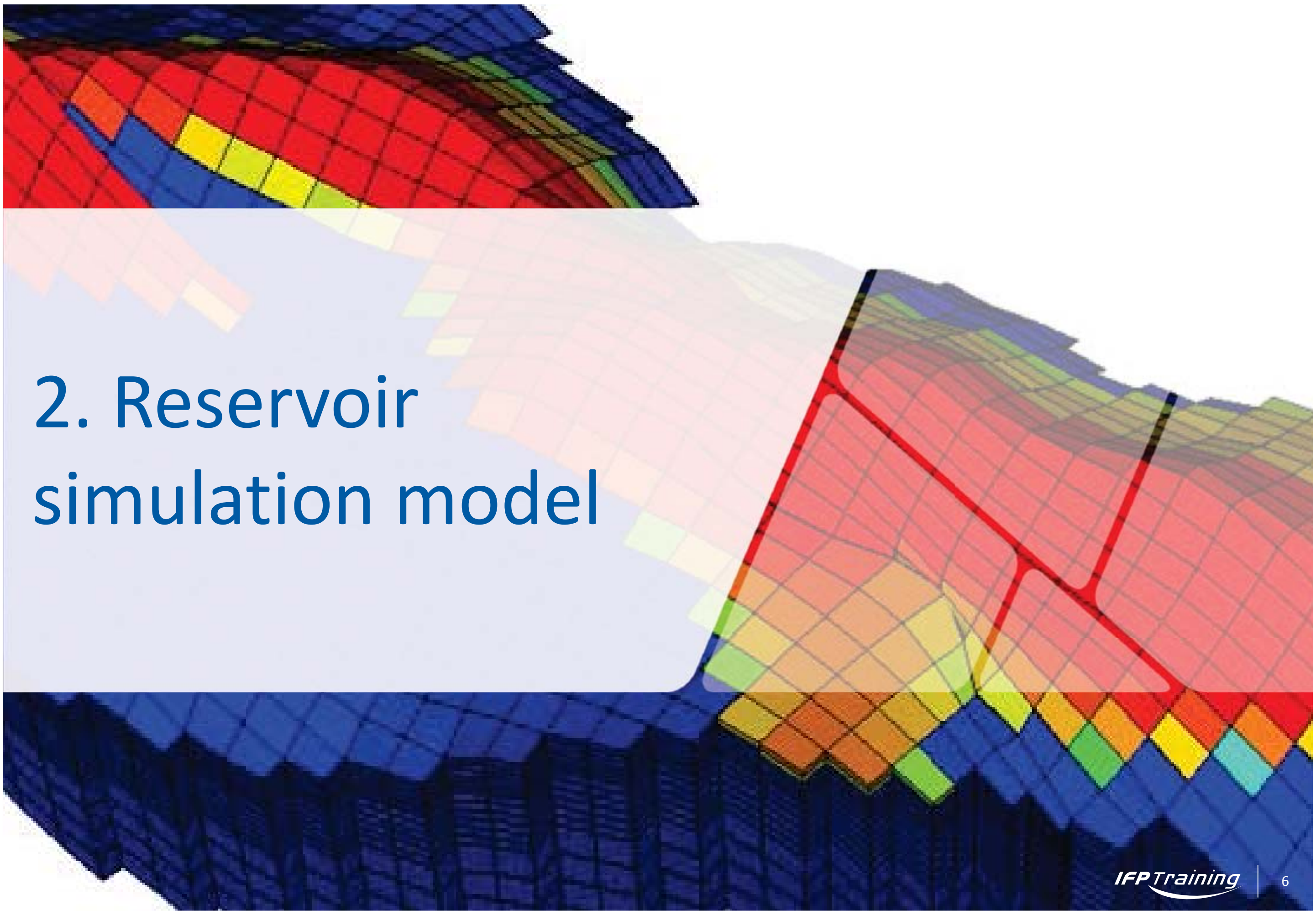
- **Dynamic Reservoir Simulation is an area of Reservoir Engineering in which numerical models are used to simulate fluids flow (typically, oil, water, and gas) through porous media, in order to predict production under a given development plan and investment strategy**

- **Early in a field life, it is essential to be able to evaluate how much hydrocarbons will be produced through time**
  - How much hydrocarbons are initially in the reservoir?
  - How much of those hydrocarbons can potentially be recovered? How much reserves?
  - How quickly can the recoverable hydrocarbons be produced?
  - How will the reservoir perform under various development scenarios?

- **Dynamic reservoir simulation is a useful tool that may help answer those questions**

At all stages of a field development, dynamic reservoir simulation may help

- **Non producing reservoir**
  - To identify best production strategy (depletion, injection…)
  - To define the well number and their architecture
  - To design surface facilities
  - To evaluate risk and profitability of the development project
  - To optimize CAPEX
- **Appraisal**
  - To identify key dynamic uncertainties
  - To define appraisal needs (contacts, faults, facies variations)
- **Producing reservoir**
  - To integrate all history production data
  - To improve reservoir description
  - To optimize oil production and recovery (infill, W.O, IOR…)
- **At all stages of the development**
  - To establish reliable production forecasts
  - To evaluate (remaining) reserves



2. Reservoir simulation model

Reservoir simulation model

- **A reservoir simulation model is a simplified numerical representation of the image that geoscientists and reservoir engineers have of a reservoir**
- **In very broad outline, it is a grid (tens to millions cells), populated with rock and fluid properties (Pres, Sat, K, Phi, Kr, Viscosity…), penetrated by wells, in which fluid flow equations can be applied**

Reservoir simulation model

- **It may be viewed as a transfer box receiving inputs and delivering outputs, but**
  - The model must not be used as a black box
  - The output data cannot be better than the input data
- **It allows reservoir engineers to understand physical phenomena within the reservoirs and to predict reservoir behavior and production under various development scenarios**
- **Uncertainties are an important aspect of reservoir simulation**
  - A potential risk would be that users could consider their results as “representing the reality”…

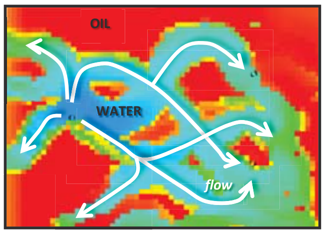
Reservoir simulation model

=

Numerical simulator

+

Set of data



- **Modeling: building the model (define parameters through integrated reservoir characterization studies, choose physical options)**
- **Simulation: running the model, either in history matching simulations or in forecast simulations**

- **There are several types of numerical simulators**
  - Black oil: One porous medium + black oil functions
  - Compositional simulator: One porous medium + EOS
  - Dual porosity simulator: Two porous media (matrix and fractures)
  - Thermal simulator: Flow + Energy equations.
- **A numerical simulator also integrates specific features such as:**
  - Grid geometry (1D, 2D, 3D, CPG...).
  - Time step management.
  - Numerical schemes (discretization of equations).
  - Resolution methods.
  - Pressure drops through tubing and surface network.
  - Well schedule.

Numerical simulator

Black oil model

- **Main assumptions**
  - 3 components (in standard conditions)
    - Oil & gas compositions are assumed constant in time
    - Oil, water & gas density are assumed constant in time
  - 3 phases (in reservoir conditions)
    - Oil is a mixture of "oil" & "gas" components
    - Gas corresponds to "gas component"
    - Water corresponds to "water component"
- **3 flow equations**
  - Oil equation
    - correspond to "oil component" contained in oil phase
  - Gas equation
    - correspond to "gas component" contained in oil & gas phases
  - Water equation
    - correspond to "water component" contained in water phase

Compositional simulator

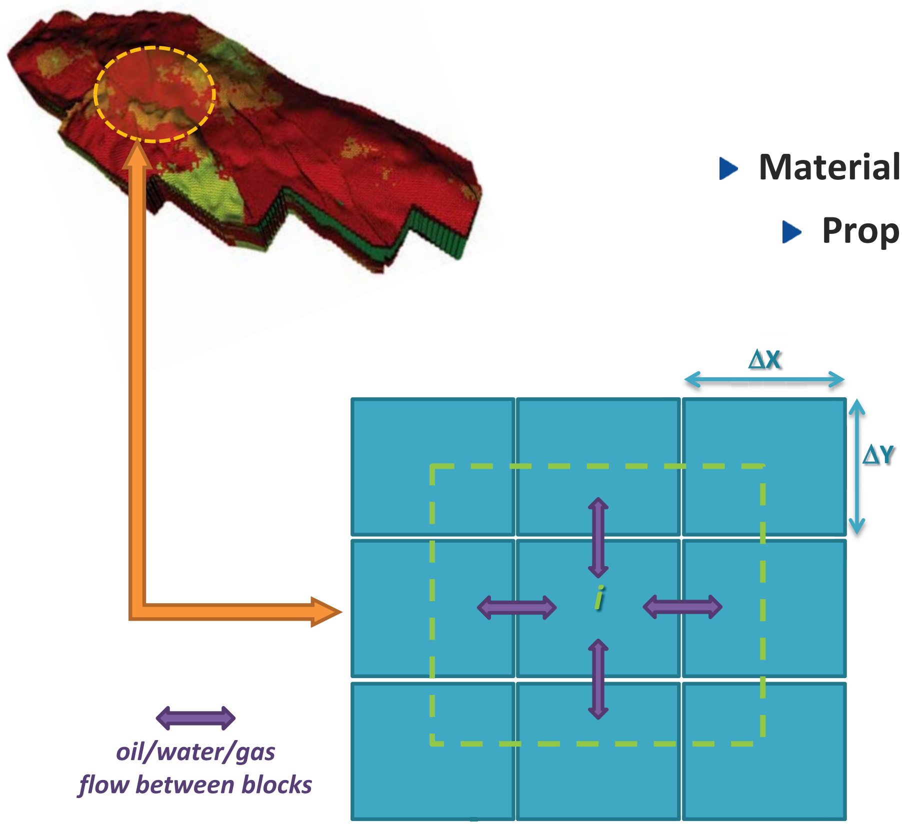
- **Black oil assumption is not valid !**
- **n Componentes: C1, C2, C3, ..., Cn**
- **3 + 3n Unknowns: Mixture mass, L & V fractions, compositions (xn, yn, zn)**
- **3 + 2n Fundamental relations:**
  - Liquid and vapour fractions: $L + V = 1$
  - Mixture compositions: $L \cdot x_n + V \cdot y_n = z_n$
  - Liquid and vapour compositions: $\sum x_n = 1 \quad \& \quad \sum y_n = 1$
  - Equilibrium constants: $y_n / x_n = k_n(P, T)$
- **We will have as many flow equations as components since we have one continuity equation per component**

Other reservoir simulators

- **Chemical**
  - polymers
  - surfactants
  - alkaline injection
  - multicomponents in oil and water phase
  - fluid/fluid and fluid/rock interactions
- **Thermal**
  - hot fluid
  - vapor
  - combustion
  - Black oil or compositional thermodynamics
  - reaction kinetics
  - Energy equation (temperature)
- **Fracture**
  - double porosity / double permeability

Simulation Model

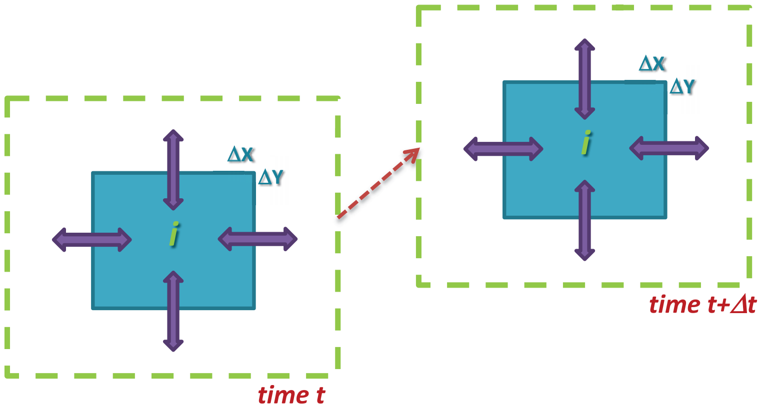
- **Space discretization**
- **Material balance equation per block**
- **Properties distribution per block**



material balance in the block 'i'

Simulation model

material balance in the block 'i'



$$(flow\ in) - (flow\ out) \pm (production\ or\ injection\ term) = accumulation\ term$$

$$\sum Q_{in} - \sum Q_{out} \pm q_i = \frac{\Delta m_i}{\Delta t}$$

MATERIAL BALANCE FOR EACH COMPONENT:
BLACK OIL MODEL: OIL, WATER AND GAS
COMPOSITIONAL MODEL: C1, C2, C3, C4... Cn

Numerical simulator: Unknowns

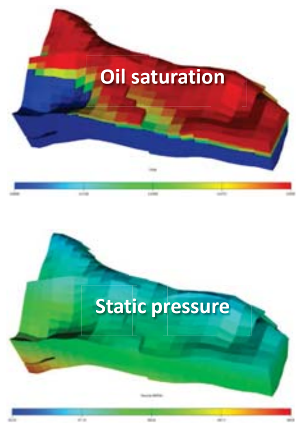
SOLVING THE MATERIAL BALANCE FOR EACH COMPONENT:
OIL, WATER AND GAS

$$\sum Q_{in} - \sum Q_{out} \pm q_i = \frac{\Delta m_i}{\Delta t} \quad + \quad \begin{cases} S_o + S_g + S_w = 1 \\ P_o - P_w = Pc_{wo} \\ P_g - P_o = Pc_{go} \end{cases}$$

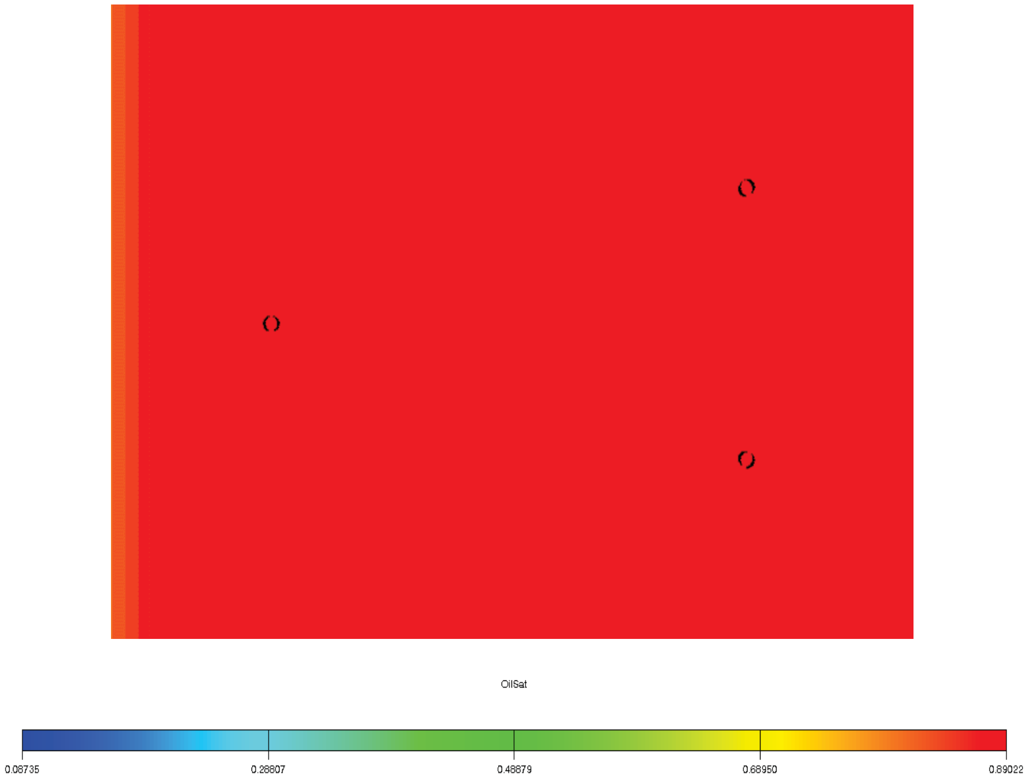
WE OBTAIN:

Pressures: Po, Pg, Pw
Saturations: So, Sg, Sw
i

at each time t
for each cell

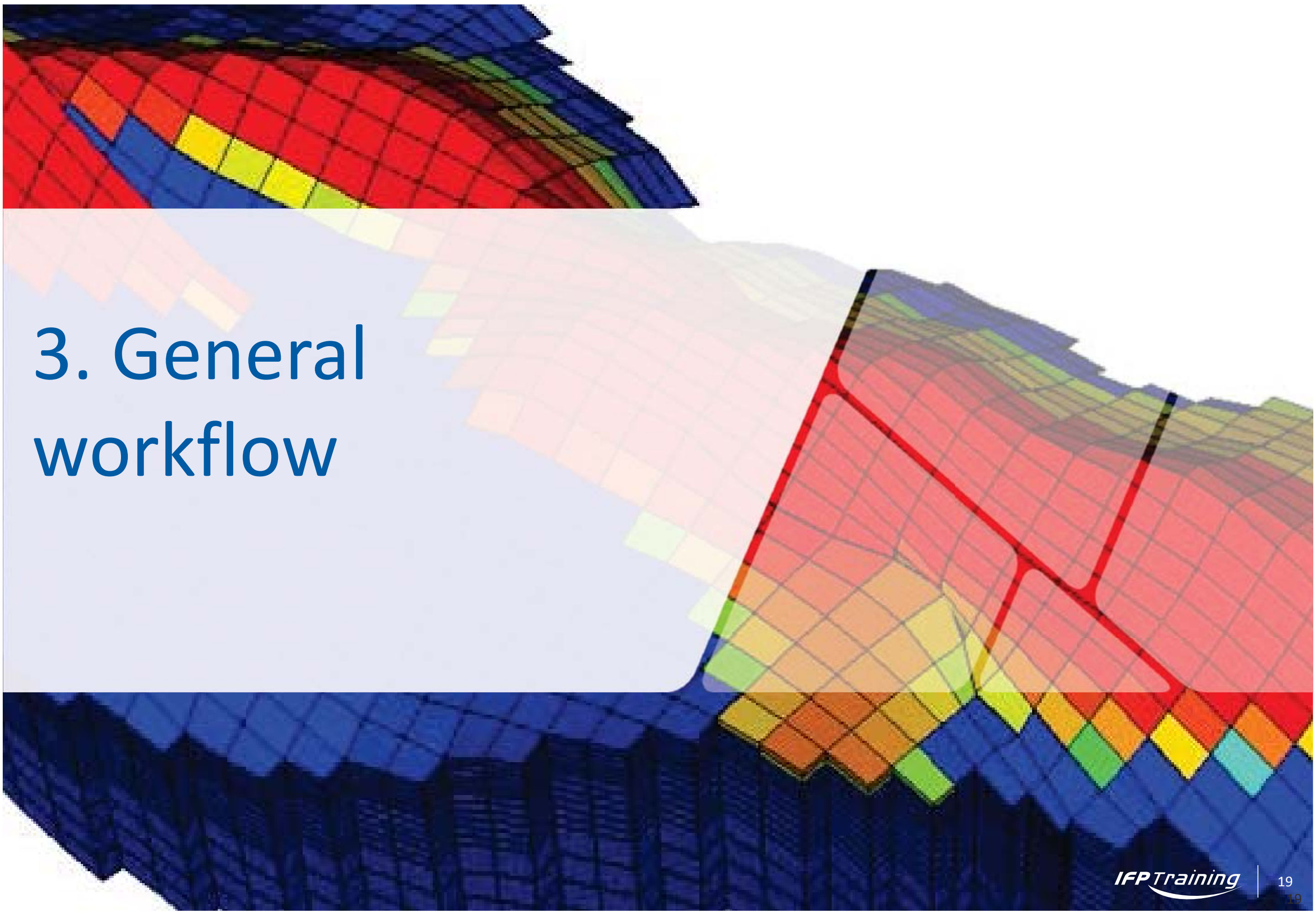


Reservoir simulation model



Key points to keep in mind

- **Reservoir Simulation Models are numerical representation of the image that geoscientists and reservoir engineers have of a reservoir**
- **Reservoir Simulation Models are made of a grid and a data set, and run with a flow simulators**
- **Various types of simulators depending on the fluids and of the geology of the reservoir**
  - Black-Oil
  - Compositional
  - Chemicals
  - Thermal
- **Simulation implies discretization in time and space**
  - Creation of a grid with one value for each physical parameter per cell
  - Time steps, during which equations are solved
  - Increasing discretization results in increasing simulation time



3. General workflow

Reservoir simulation planning

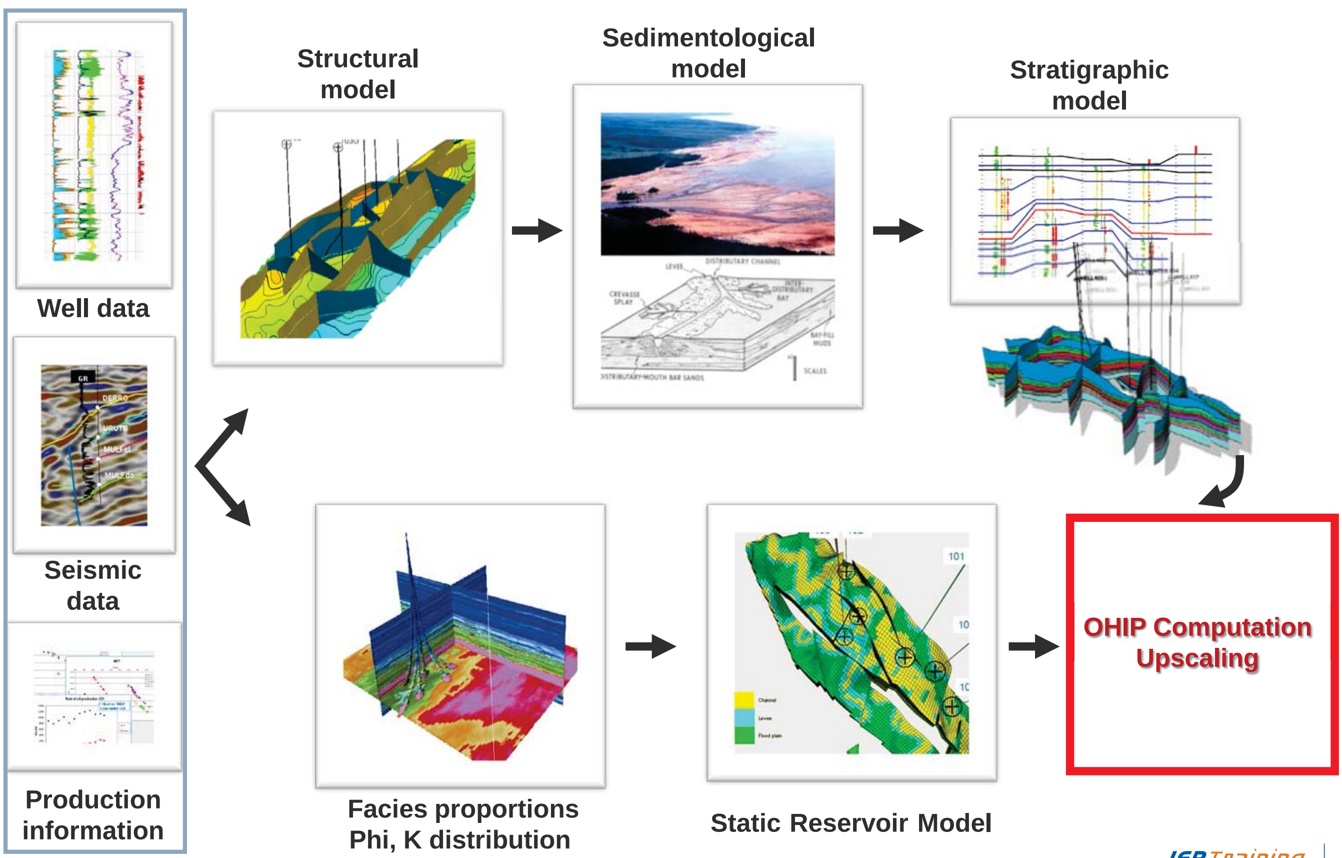
- **Reservoir simulation study duration: from weeks to years**
- **Necessity to plan carefully the study to give correct results in time, before to take decisions for the field management :**
  - Problem definition
  - Data review
  - Data acquisition
  - Approach selection: 1D, 2D, 3D... Black oil, compositional... Double f, thermal, chemical
  - Reservoir characterization – build geological static model
  - Upscaling to generate dynamic reservoir simulation model
  - Computing support
  - Initialisation
  - History matching
  - Prediction
  - Reporting

Reservoir simulation model

Data set workflow

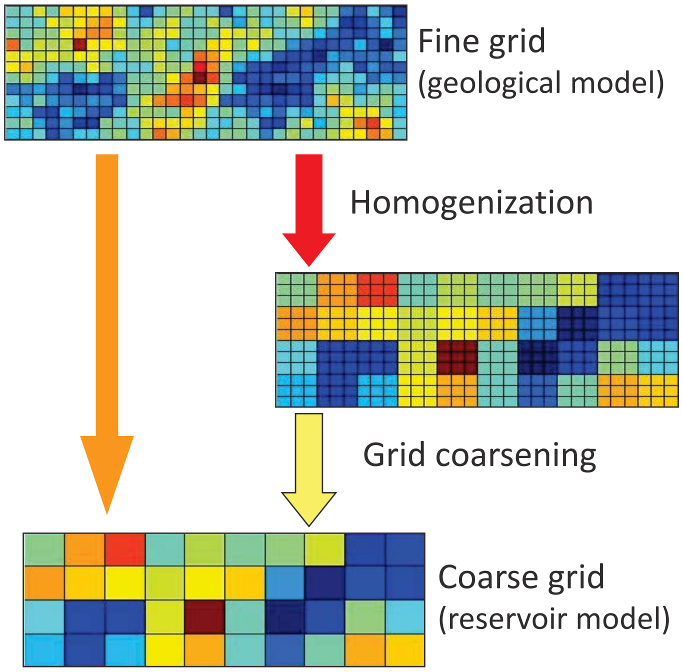
- **Reservoir characterization**
  - Depositional environment, structure, rock and fluid properties
- **Geological model**
  - Fine grid model filled up by automatic distribution methods; calculation of hydrocarbons in place volumes
- **Upscaling process**
  - Average small cells properties to fill up larger cells
- **Reservoir simulation model**
  - Coarse grid model for history match and prediction runs

Reservoir modeling workflow

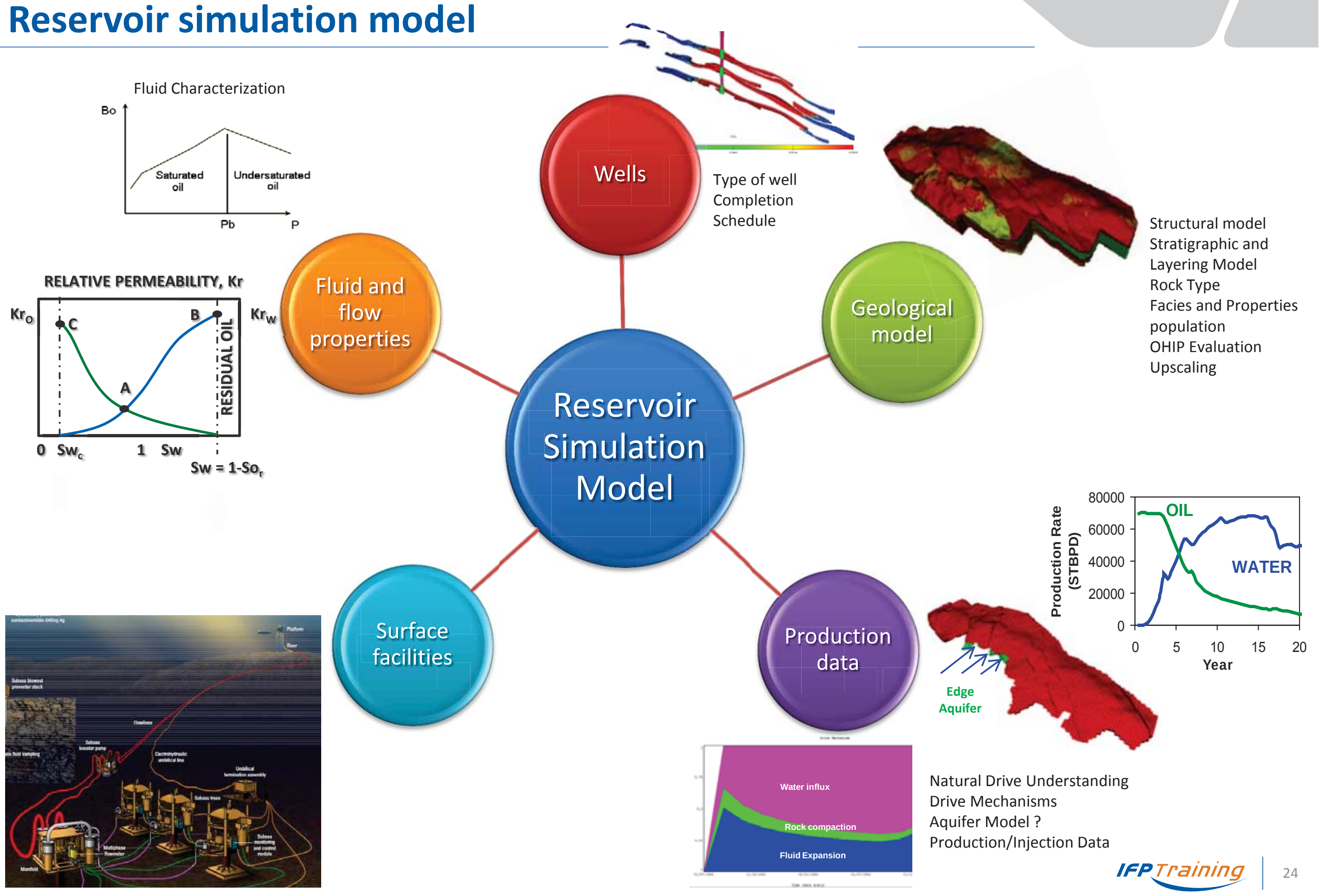


Upscaling

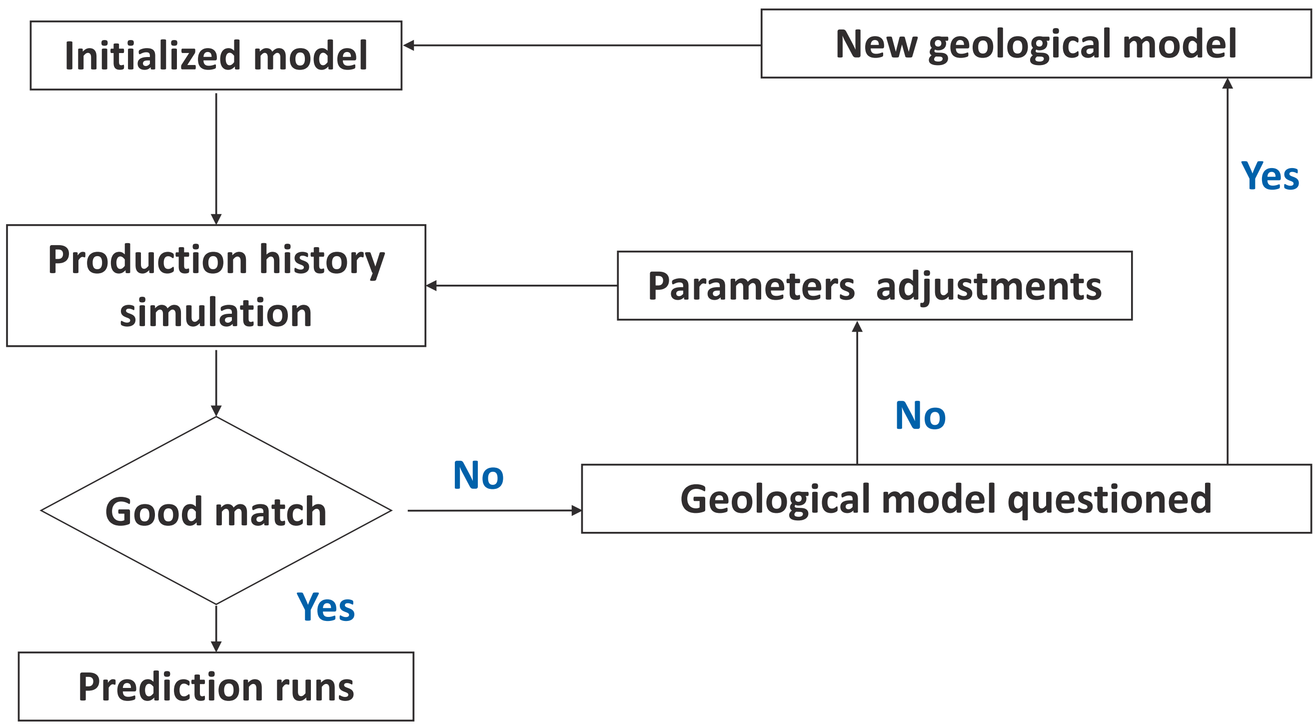
- Geological model contains a very large number of grid blocks. This level of resolution is generally incompatible with the computing capabilities of numerical flow simulators.
- To do so, fine grid blocks are grouped in aggregates: coarse grid blocks. The basic problem is to determine the equivalent properties of the coarse gridblocks.



Reservoir simulation model



General workflow



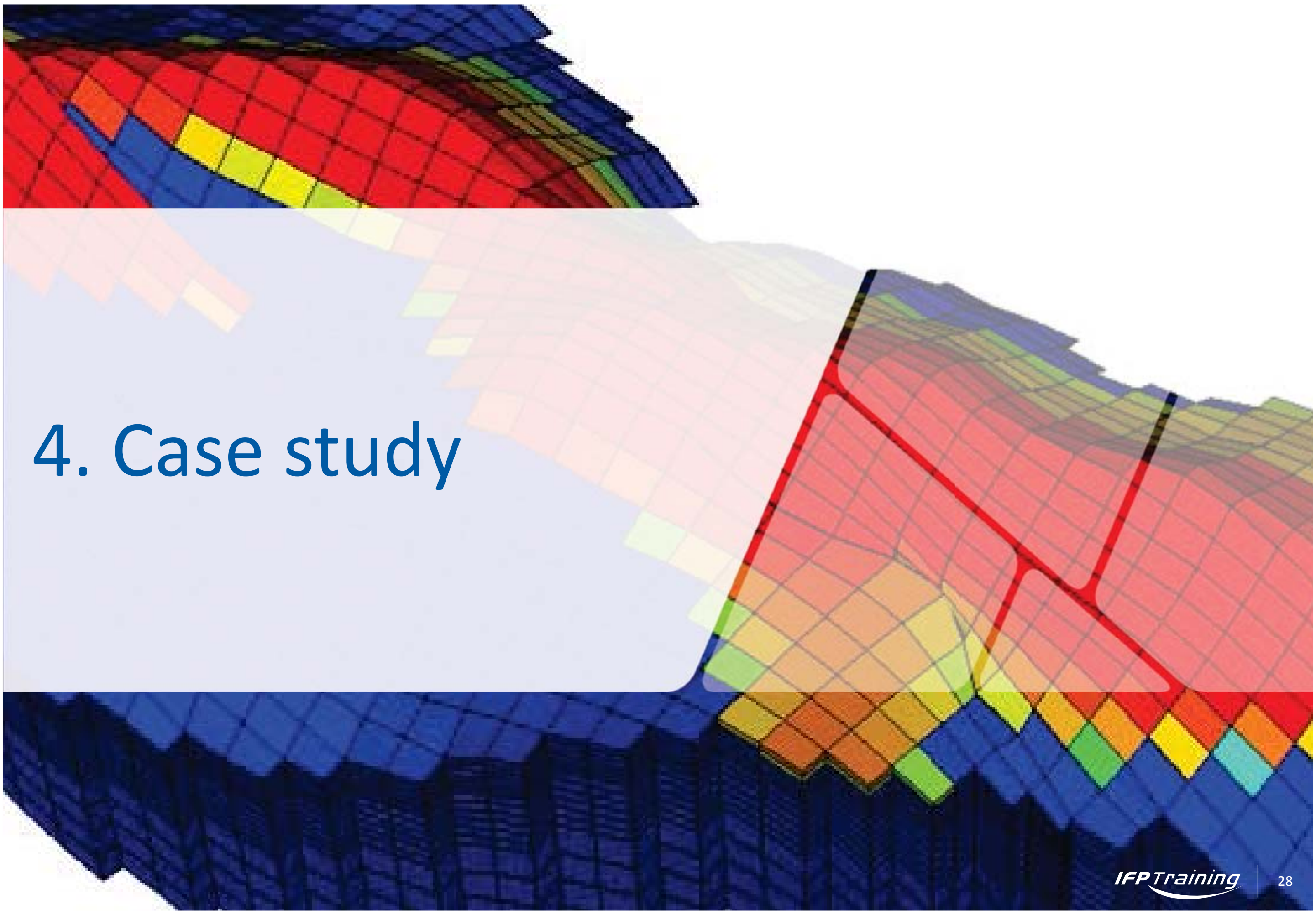
General workflow

Predictions

- **Predictions can be run once history match has been completed. The objective is to predict the future performance of the reservoir under different exploitation scenarios**
- **Results of major interest are:**
  - Future oil performance
  - Future water-cut and GOR evolution
  - Pressure evolution
  - Fluid contact evolution
  - Work-over requirements
  - Drilling requirements
  - Surface facilities requirements
  - Estimate the recovery factor
  - Estimate reserves range

Key points to keep in mind

- **Reservoir Simulation workflow**
  - Data review and model approach
  - Building the static model, upscaling and building the dynamic model
  - Running simulations: history match, prediction runs
- **Use mass balances and simple tools to check your data**
- **Check the validity of data and results**
- **A good model is one that provides an accurate flow representation, with:**
  - An adapted 3D grid
  - A realistic set of petrophysical parameters
  - A successful upscaling
- **Reservoir Simulation Models allow to integrate the data coming from various disciplines: Geology, Geophysics, Well Tests, Petrophysics, PVT…**
- **The model is reliable at current time t, but at t+Δt?**



4. Case study

Integrated workflow

Introduction | Structural Modelling | Geological modelling | Reservoir modelling | Development planning | Conclusions

Integration

Quality control

Structural Modelling

- Seismic Interpretation
- Well to Seismic Calibration

Geological Modelling

- Core and log analysis
- Depositional environment
- Well correlation
- Distribution of facies & properties

Reservoir Modelling

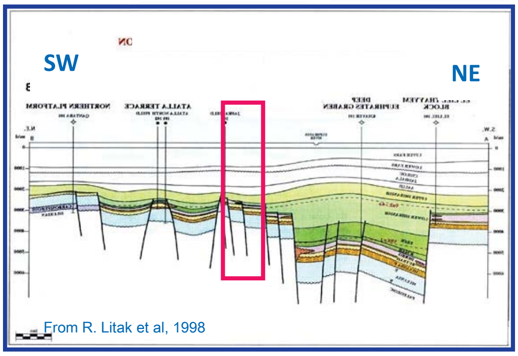
- Aquifer dimensioning
- Dynamic data synthesis
- Production mechanisms

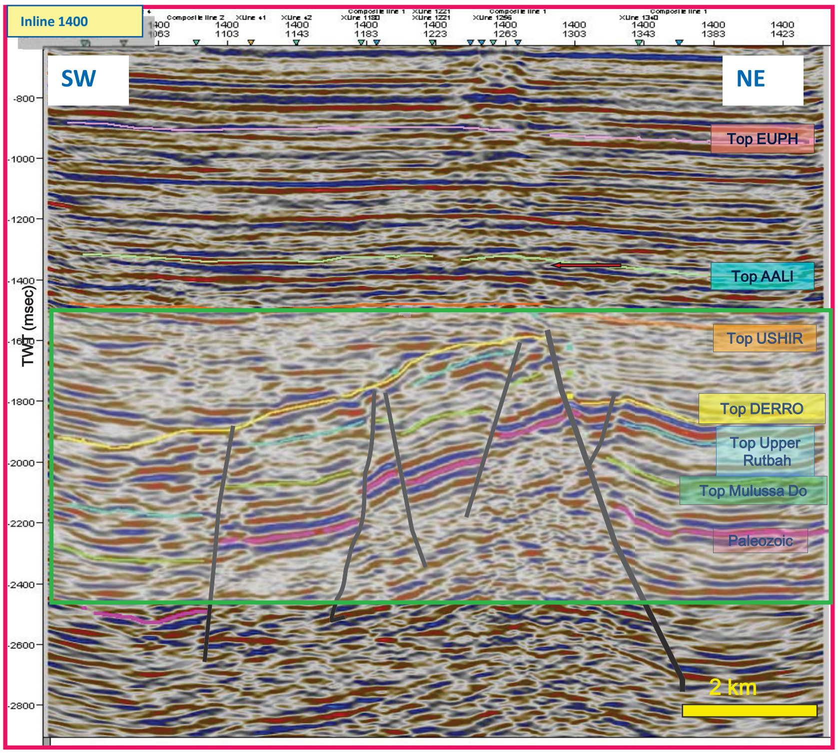
Field Development Planning

- Reduction of main uncertainties
- Appraisal plan
- Production forecast

Seismic interpretation

Introduction | Structural Modelling | Geological modelling | Reservoir modelling | Development planning | Conclusions



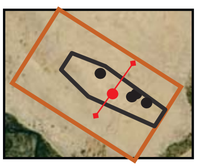


Seismic data base

180 km² with 3D PSTM seismic with a Seismic Datum reference (+300m MSL)

Well logs data for calibration (Well 103)

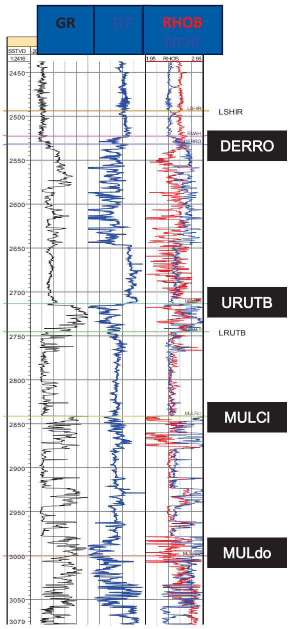
- **VSP, Sonic and Density**
- **Synthetic seismogram**
- **Seismic to well tie**

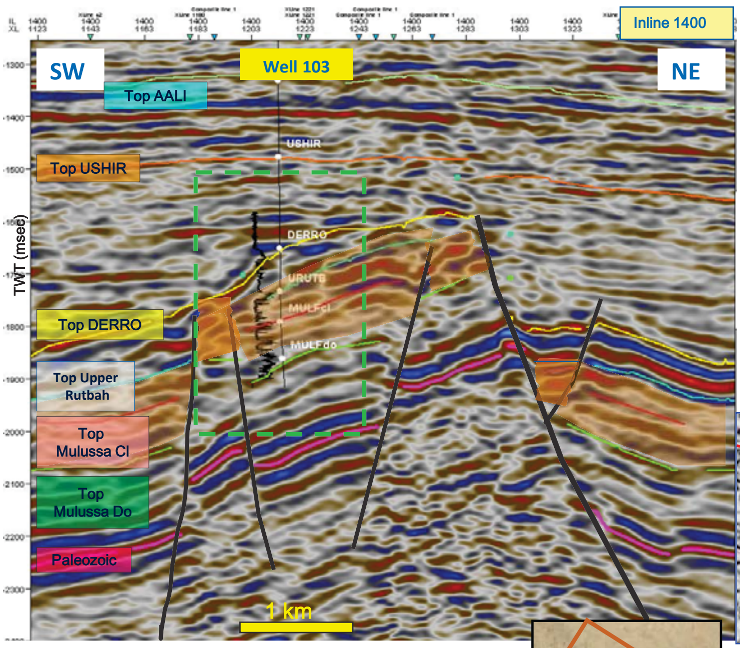


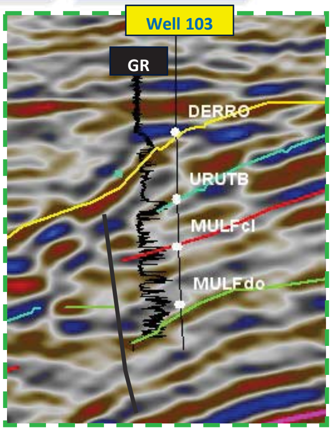
Well to Seismic calibration

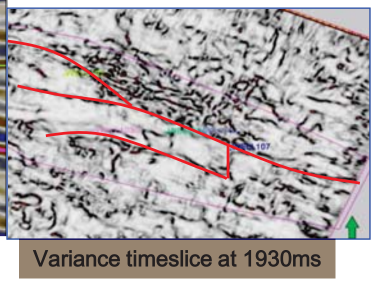
The main horizons:

- Top Derro
- Top Upper Rutbah
- Top Mulussa Cl
- Top Mulussa Do

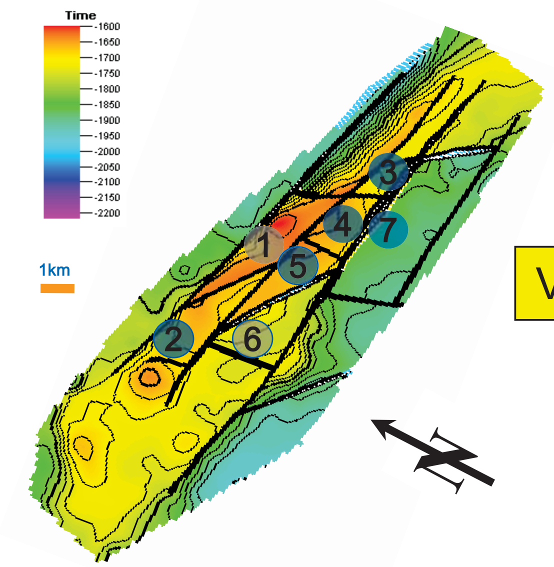








Structural model



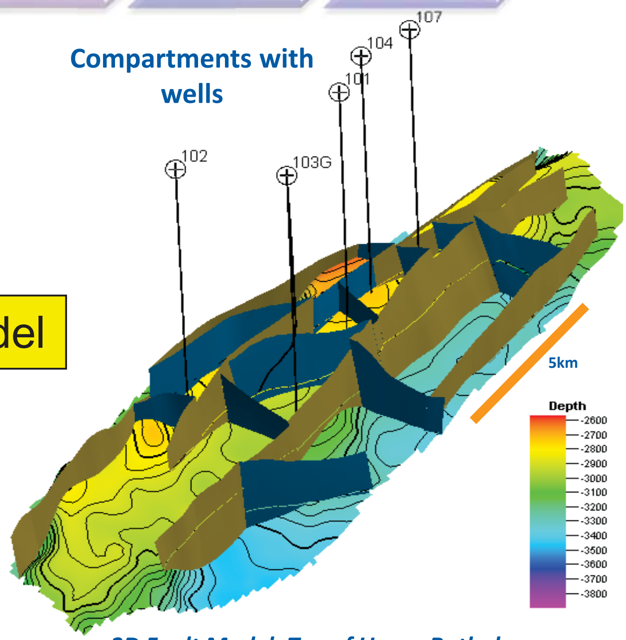
Time Structure Map: Top of Upper Rutbah

Time [ms]

Velocity Model

Depth [m]

Compartments with wells



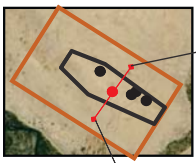
3D Fault Model: Top of Upper Rutbah

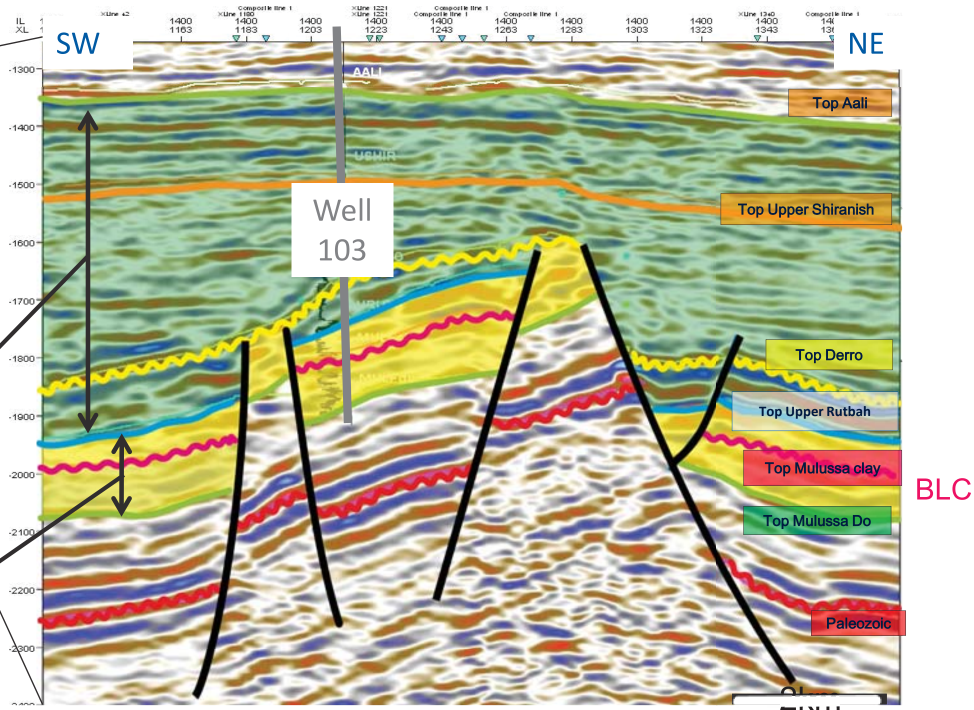
➡ Two fault trends (NW- SE & NE-SW) split the field into seven compartments

Reservoir depth is from 2500m to 3000m TVDSS

Cross section of the Field

Introduction | Structural Modelling | **Geological modelling** | Reservoir modelling | Development planning | Conclusions



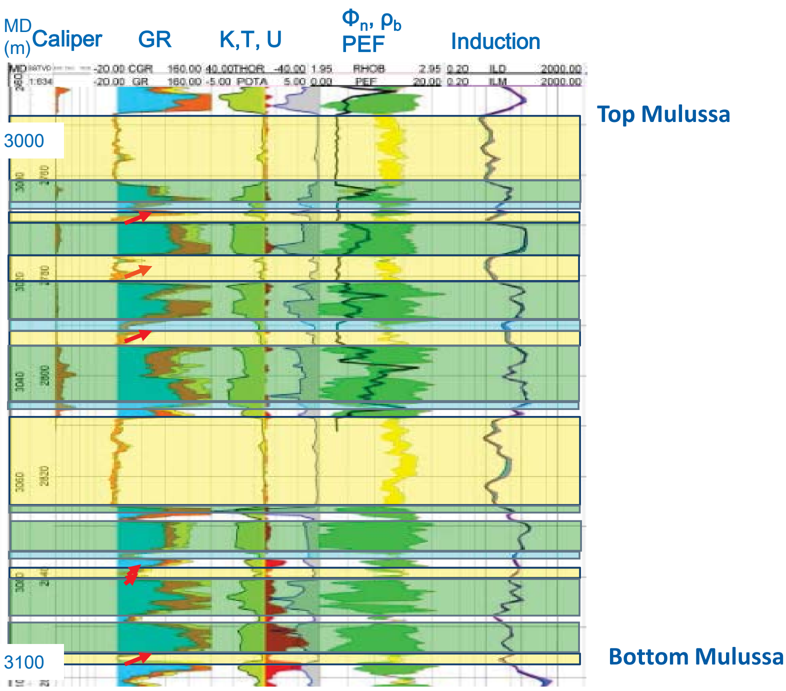


SEAL:
- marly limestone in SHIRANISH
- shaly conglomerate in DERRO

RESERVOIR:
- E. Cretaceous sandstone in RUTBAH
- L. Triassic sandstone in MULUSSA

Depositional Environment: MULUSSA

Introduction | Structural Modelling | **Geological modelling** | Reservoir modelling | Development planning | Conclusions



Packages of sand in fluvial channels

Shaly packages of sand in levees

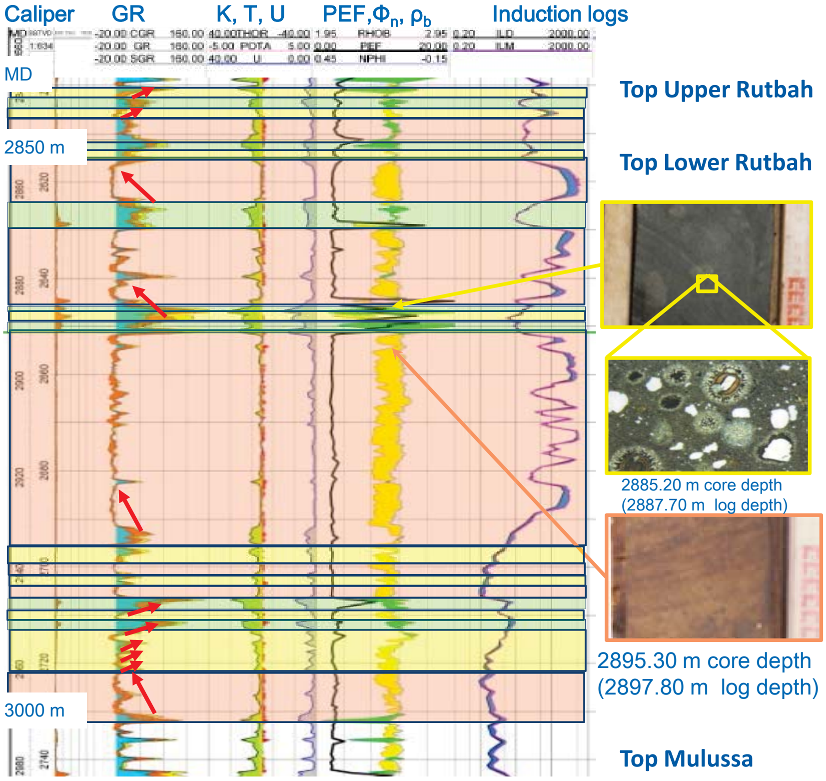
Shales packages corresponding to floodplains

FLUVIAL SYSTEM

Buchans Brook, http://rainbowfish.angfaqld.org.au

Depositional Environment: RUTBAH

Well 102



Interbedded fining upward packages of sand and shaly layers corresponding to **distributary channels**

Coarsening upward thick packages of sand corresponding to **distributary mouth bars**

Deltaic shales

DELTAIC SYSTEM

Buchans Brook, http://gsc.nrcan.gc.ca

Facies identification

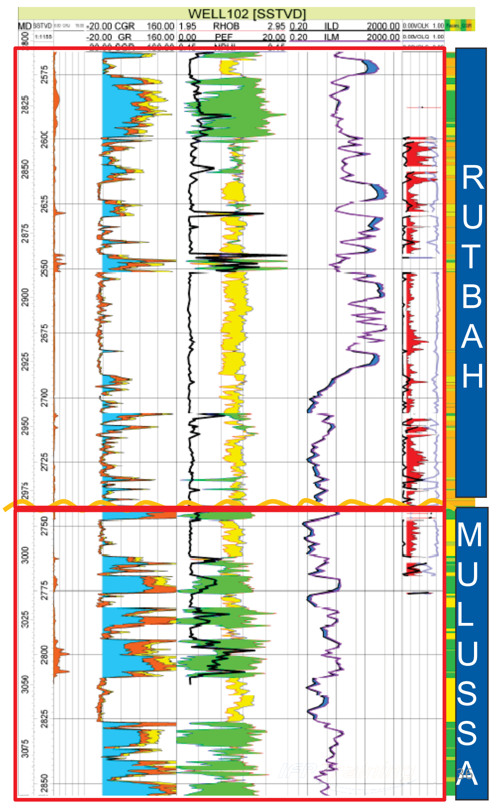
In RUTBAH (from better to worse facies):

	GR cut-off
Deltaic sand good quality (distributary channels and distributary mouth bars)	0-30
Deltaic sand poor quality (cemented and shaly parts of distributary mouth bars)	30-70
Shale drape	70

In MULUSSA (from better to worse facies):

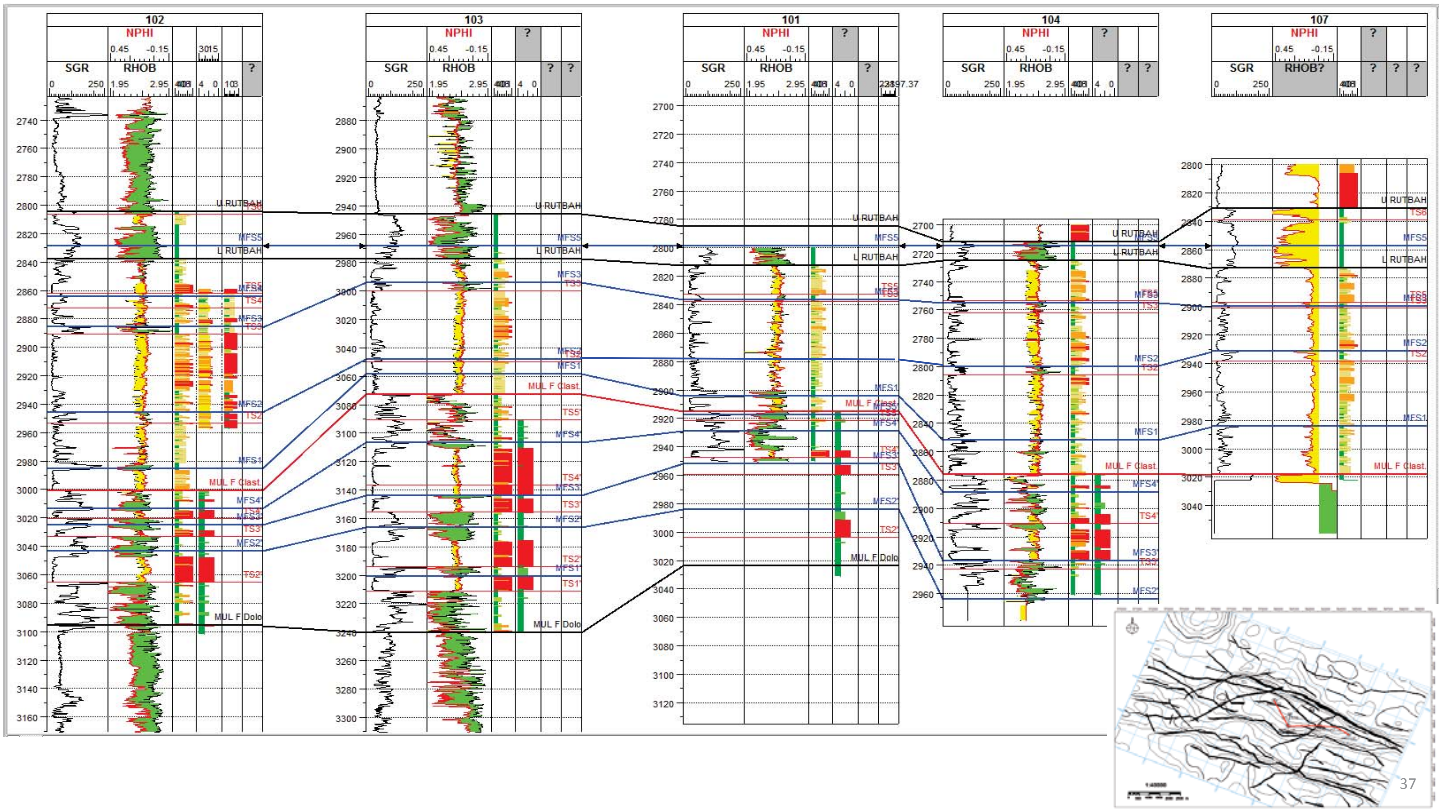
Given in the dataset :

channel
levee
floodplain

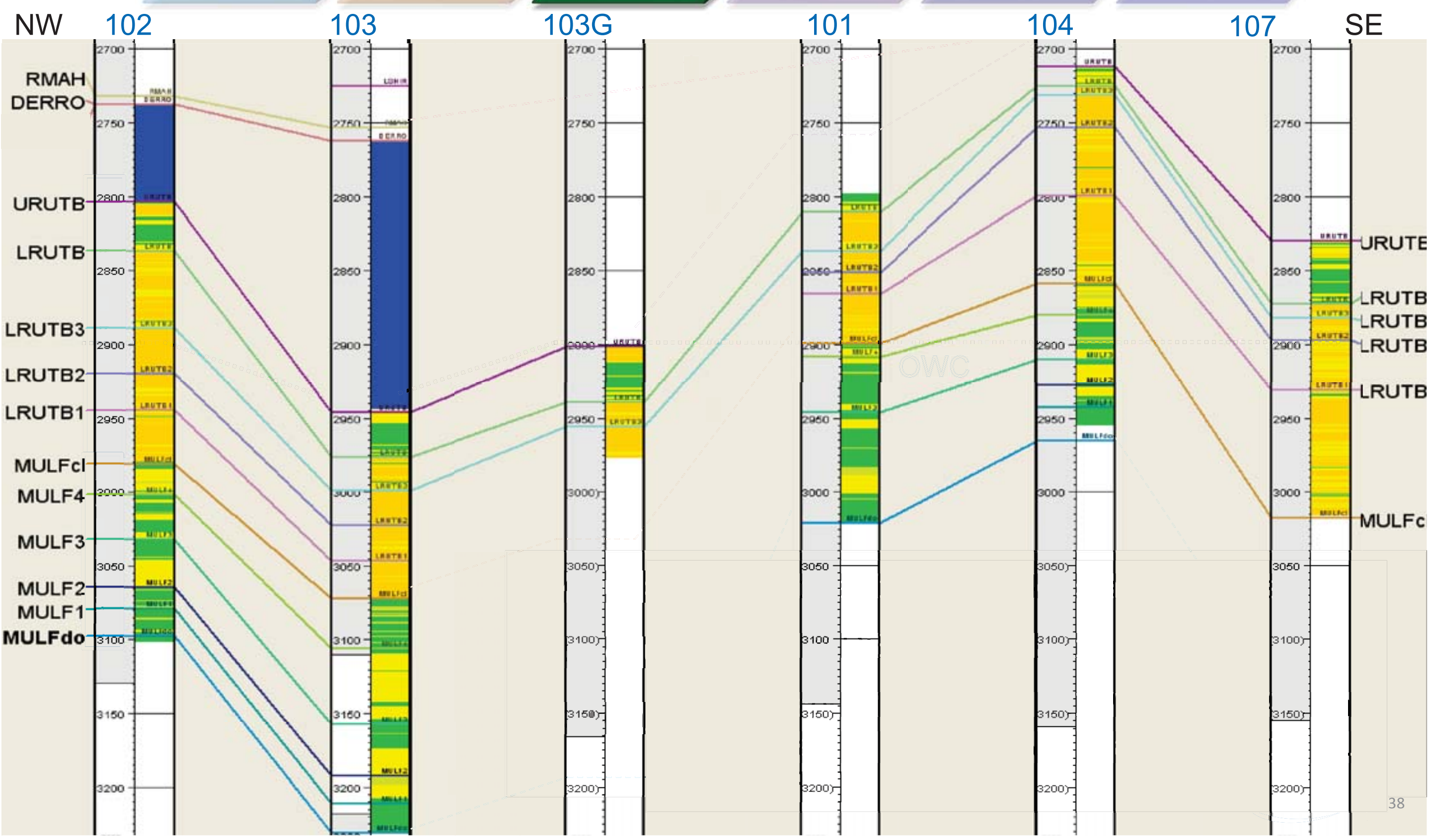


WELL102
Logs Core

MFS Well to well correlation



Well correlation in structural position



Facies distribution

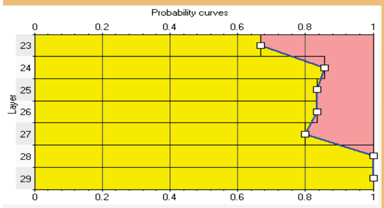
Deltaic system: RUTBAH

Sequential Indicator Simulation for deltaic sand

Fluvial system: MULUSSA

Object modeling for channels and levees

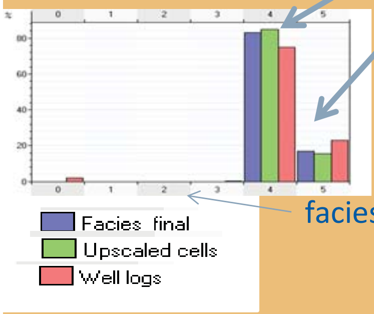
For each flow unit:



Using proportion curves calculated after well blocking for each sequence

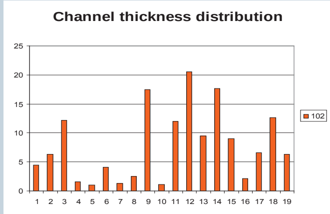
Good sand

Shaly sand

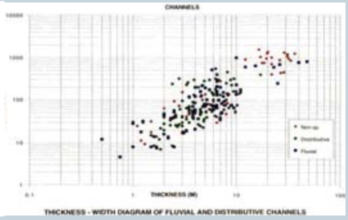


Quality control on frequencies of each facies

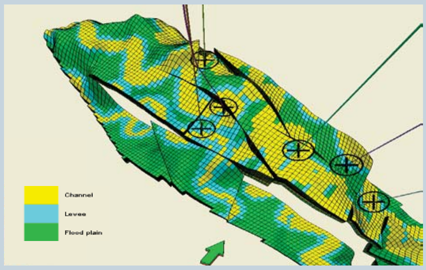
facies



Well data



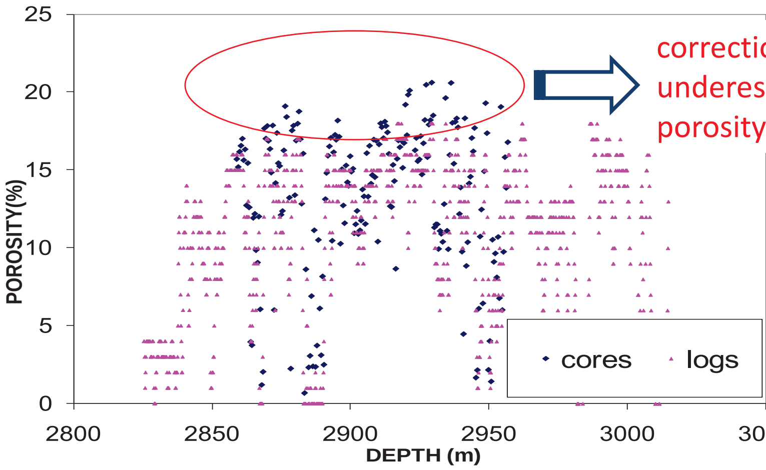
Geological cross plot



Statistical **and visual quality control**

Quality control before simulations

Porosity distribution:



correction of underestimated log porosity

Net to Gross distribution:

	POROSITY	NTG
Upper Rutbah	6%	14%
Lower Rutbah	13%	74%
Mulussa	15%	24%

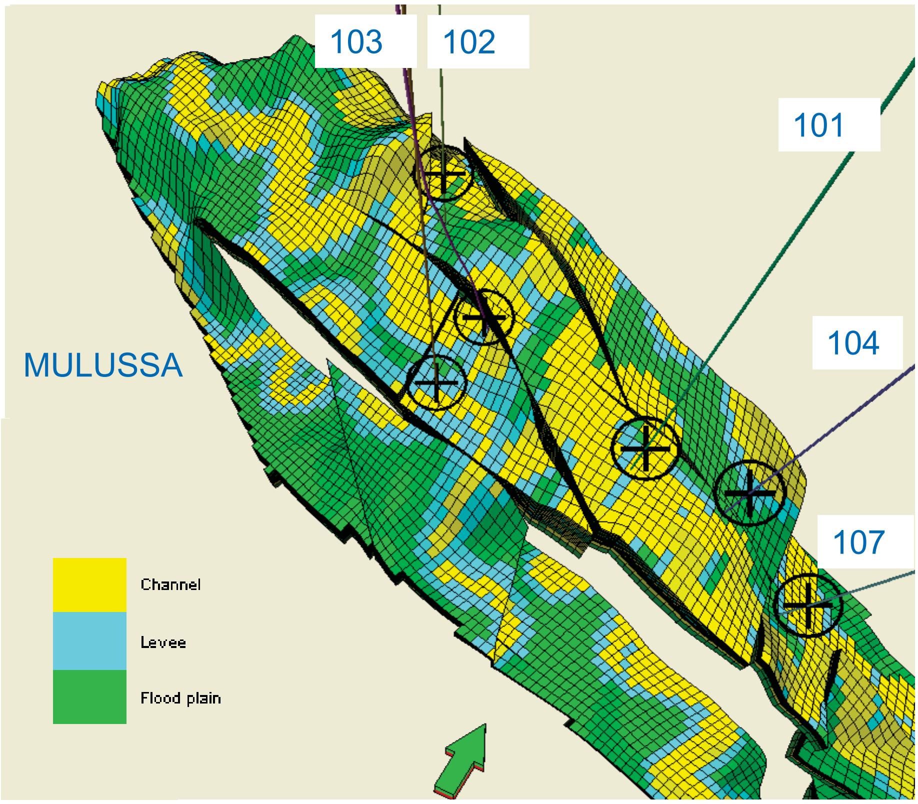
good consistency with analogs (Omar field)

Permeability values and well test results:

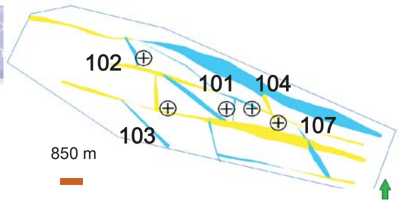
	WELL TEST(D.m)	MODEL(D.m)
101	120	90
102	95	80
104	60	100
107	65	40

good representation of tests

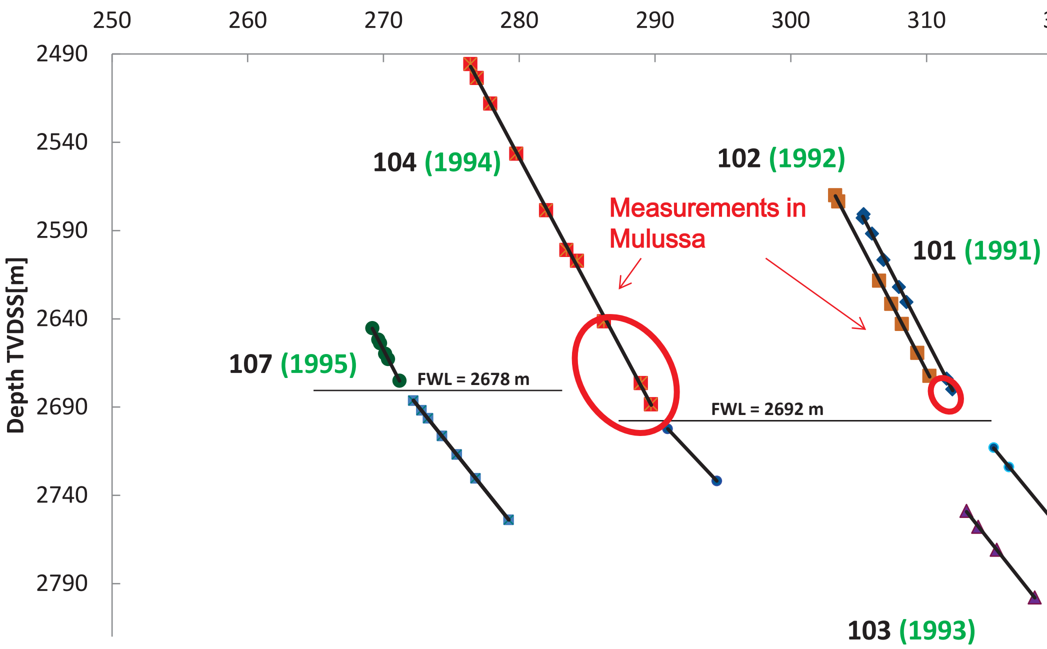
Final model



Dynamic data synthesis



- **RFT (5 wells)**



FWL :2692 m

Continuity of slopes after depletion => no horizontal barriers

One single Reservoir (Mulussa and Rutbah)

Dynamic data synthesis

Introduction | Structural Modelling | Geological modelling | **Reservoir modelling** | Development planning | Conclusions

- RFT (5 wells)
- **PVT (Eclipse format)**
- **SCAL (Eclipse format)**
- Production history
- Well test interpretation

Key features from PVT and SCAL:

Light oil (35° API)

Decreasing dissolved gas with depth

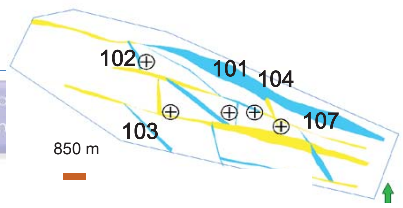
Five rock types for dynamic model according to porosity

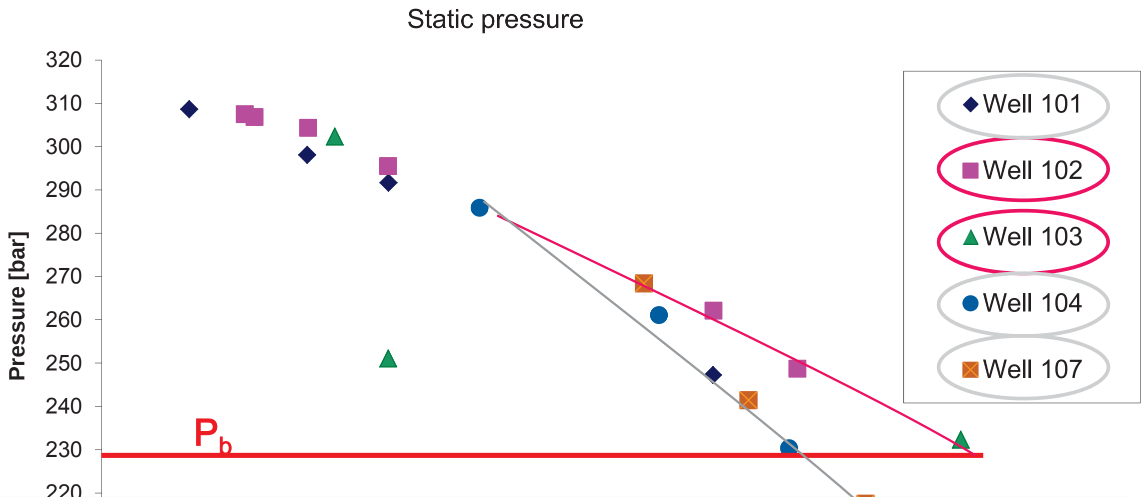
Displacement efficiency around 0.7

Property \ Rock type	RT1	RT2	RT3	RT4	RT5
Φ	> 15%	12,5 to 15%	10 to 12,5%	8 to 10%	
S_{wi}	5%	8%	14%	20%	45%
K_v/K_h	0,8	0,5	0,1	0,05	0,05
S_{or}	24%	24%	30%	27%	19%

Dynamic data synthesis

Introduction | Structural Modelling | Geological modelling | **Reservoir modelling** | Develo… plan…





Conclusions:

- During production history Pstatic reached Pb
- Wells 101,104,107 less maintained in P => no P support on the East

Dynamic data synthesis

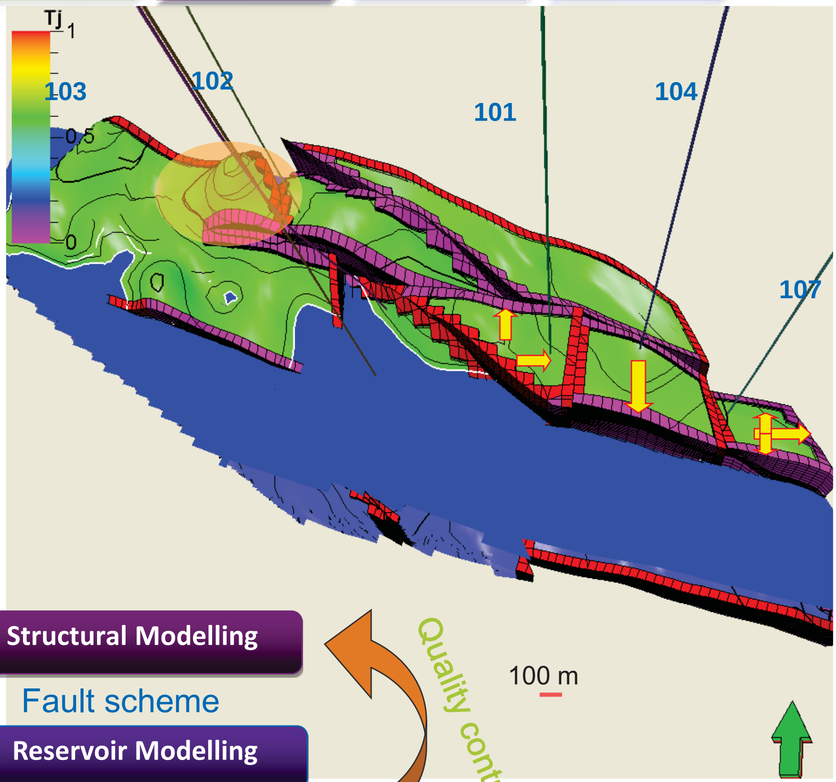
- RFT (5 wells)
- PVT (Eclipse format)
- SCAL (Eclipse format)
- Production history
- **Well test interpretation**

101: Two intersecting boundaries at 90° at 15 m and 505 m

104: One no flow at 370 m

107: Three no flow at 329m , 329 m, 674 m

102: No boundary



Structural Modelling

Fault scheme

Reservoir Modelling

Well test

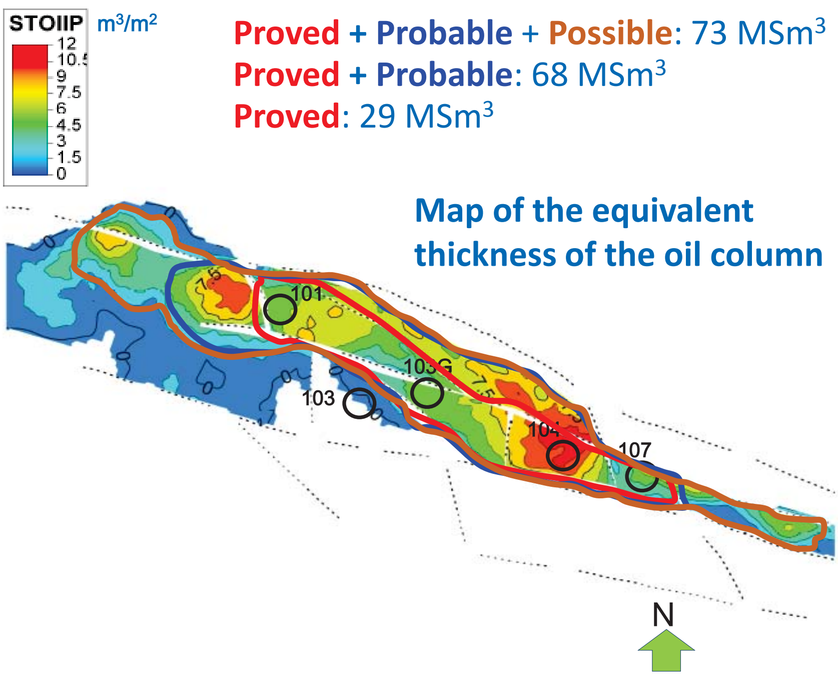
Quality control

Estimation of oil in place

Proved + Probable + Possible: 73 MSm^3
Proved + Probable: 68 MSm^3
Proved: 29 MSm^3

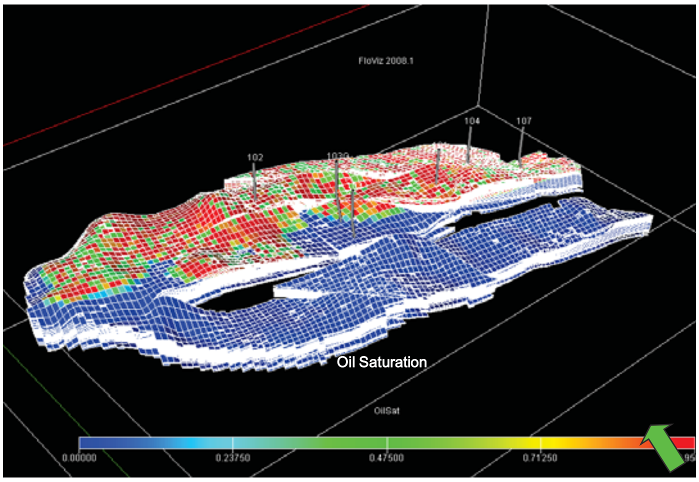
Deterministic approach

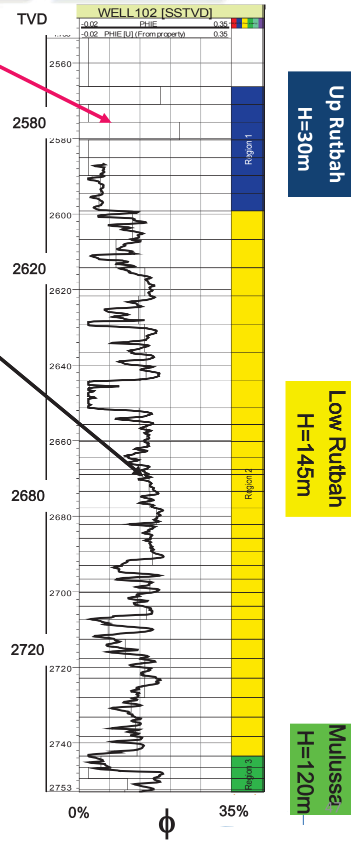
- **Proved: compartments with oil column**
- **Probable: compartments confining with proven zones**
- **Possible: the remaining area**



Map of the equivalent thickness of the oil column

Eclipse grid





44x142x59 cells in each direction

370 000 cells

270 000 active cells

100x100x7 m average cell

NO UPSCALING

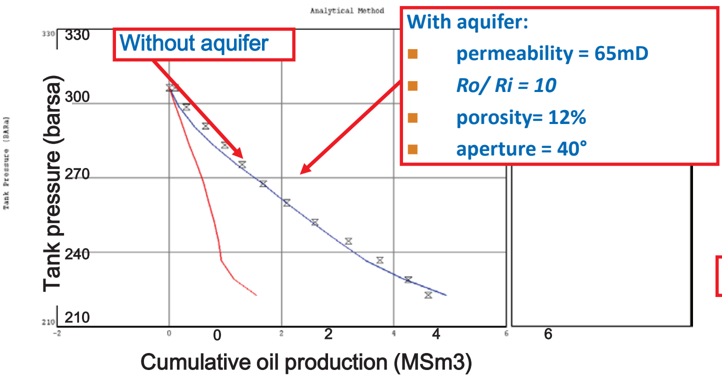
STOIIP 68 MSm^3(427.7 MMstb)

Up Rutbah: 6.1 MSm^3 (9%)

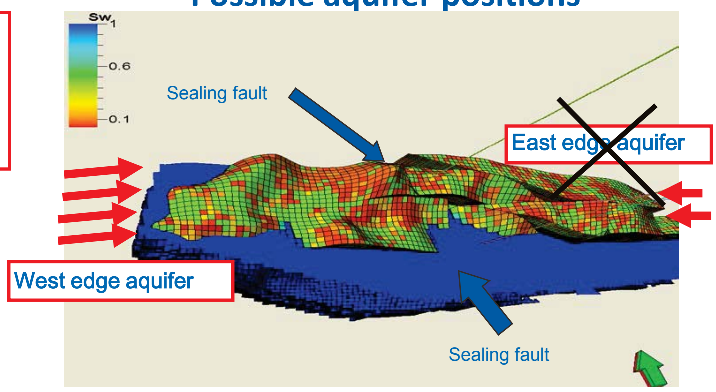
Low Rutbah: 58.4 MSm^3 (86%)

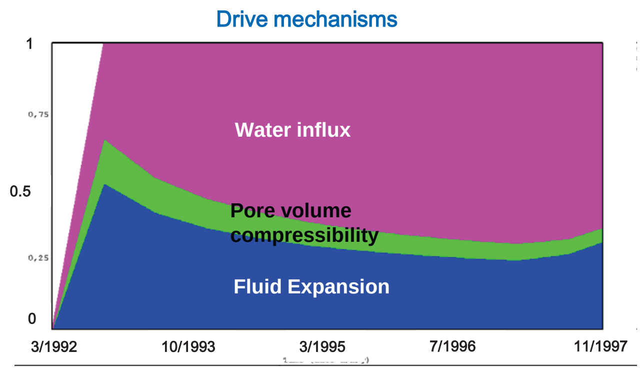
Mulussa: 3.5 MSm^3 (5%)

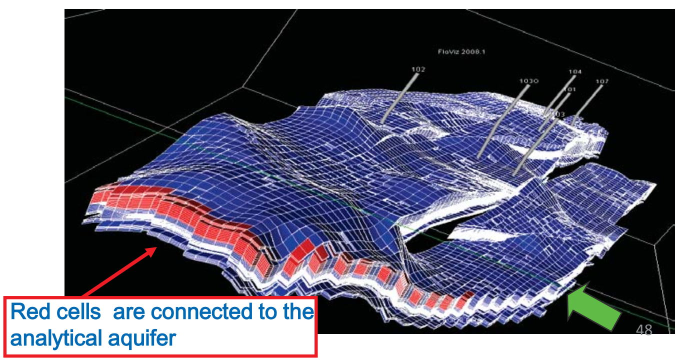
Material balance



Possible aquifer positions



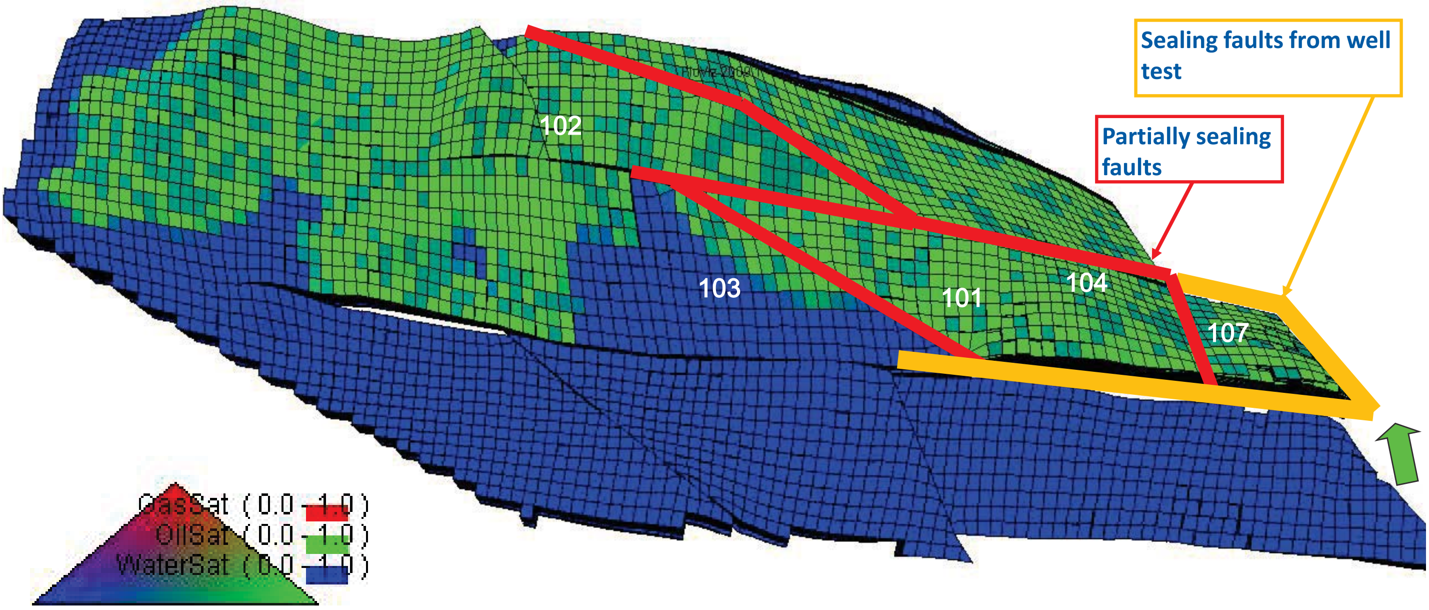




Sensibility runs

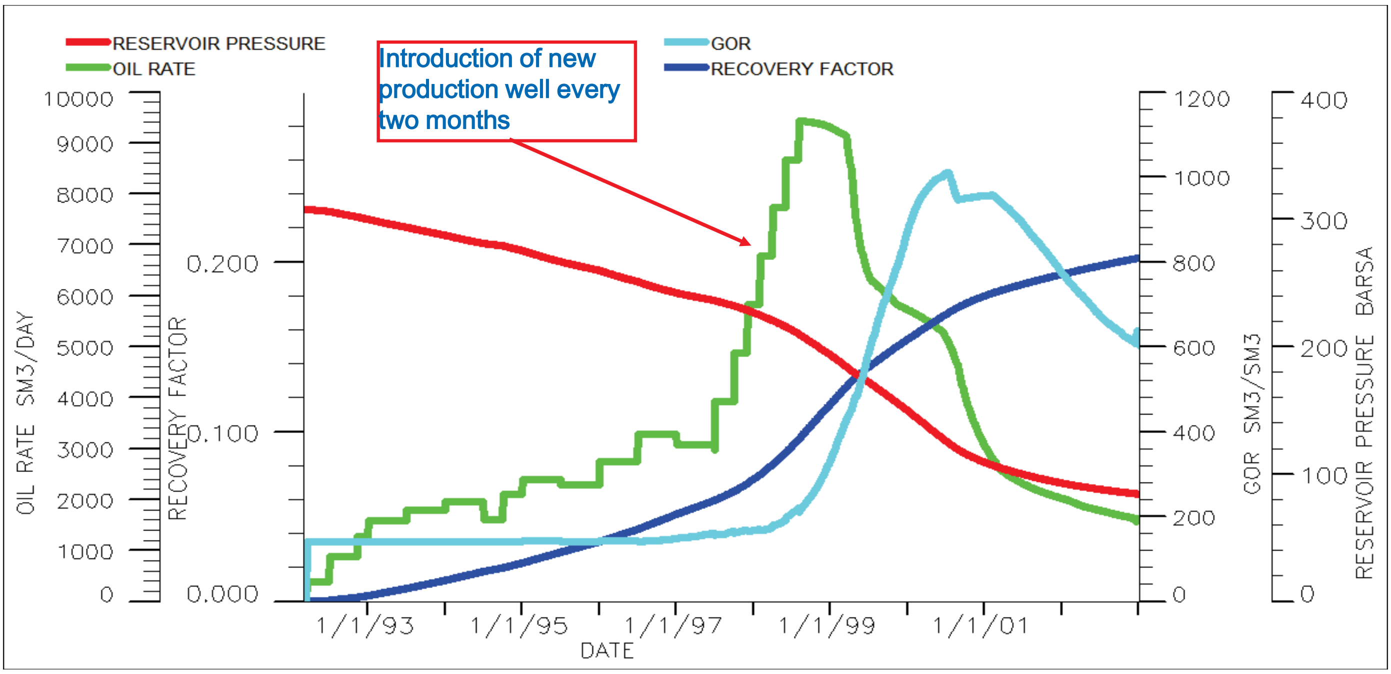
- **Crucial parameter: transmissibility of faults**

Four partially sealing faults (transmissibility multiplier 0.01)



Production profile

- **No plateau**
- **After 10 years of production: RF = 20%, reservoir pressure 80 bar and oil rate 1600 Sm³/d**



Final field development plan

Introduction → Structural Modelling → Geological modelling → Reservoir modelling → Development planning → **Conclusions**

Recommendations

- In case of the problem of water availability for the start of the water injection => further optimization the solution gas drive or possible implementation of gas injection
- The development plan should have further investigations regarding investments

Wells	• 6 (one – side track) wells were already drilled and 2 were not used for production • 8 wells (1 – side track) should be drilled; totally 10 producers and 4 injectors
Production	• Oil production – 34.6 MSm3 (Recovery factor – 51%) • Gas production – 5.3 BSm3
Constraints	• 4 years duration of plateau rate (8500 Sm3/d) • Injected water – 78 MSm3 (40% recycled)

Reserves and Ressources classification

Week#2

PTTEP Algeria

November 2016

IFP Training

Outline

1. **Introduction**
2. **Reserves classification**
3. **Introduction to risks and uncertainties**

Generalities

Accumulation versus Reserves

- Accumulation: Volume of hydrocarbons in place to be estimated = Hydrocarbon deposit (reported in STANDARD Conditions)
- Reserves: Part of this volume that can be recovered by technical and economic procedures
-
- The reserves are defined as the estimated quantities of crude oil, natural gas, gas condensate, liquids recovered from natural gas, and associated substances, that are considered commercially viable to recover from a given accumulation, beginning at a certain future date, under specified economic conditions, using current technology, and subject to present-day legal restrictions

What are Reserves?

- Reserves are hydrocarbons which are anticipated to be commercially recoverable from a given date forward from known reservoirs by specified techniques (associated Development Plan) and at specified economic conditions
- Key concepts:
  - Commercially recoverable
  - Known reservoirs (excludes exploration)
  - Remaining reserves
  - Specified techniques
  - Specified economic conditions

2. Reserves classification

Reserves - Definitions

- **Proved:**
  - Volumes which are discovered and can be produced under current economical conditions, with a clearly identified development scheme, and with a 90% chance of being exceeded.
- **Probable:**
  - Volumes which are discovered and have a reasonable probability of being produced with current technology and economical conditions, with a 50% chance of being exceeded.
- **Possible:**
  - Volumes discovered or induced and can be produced with expected technology improvements, or with more favorable economical conditions, and with a 10% chance of being exceeded.

Calculation methods for the evaluation of accumulations

- **Deterministic approach: Volumes are classified as Proven, Probable or Possible. For each category, a deterministic calculation is done.**
- **Probabilistic method: each parameter is attributed a range of values and calculations are incorporated in a "Monte Carlo" analysis.**

Deterministic	Probabilistic	Explo
1P Proved	P90 Usually > 1P	Mini
2P Proved + Probable	P50 Roughly 2P	Mode
3P Proved + Provable + Possible	P10 Usually < 3P	Maxi

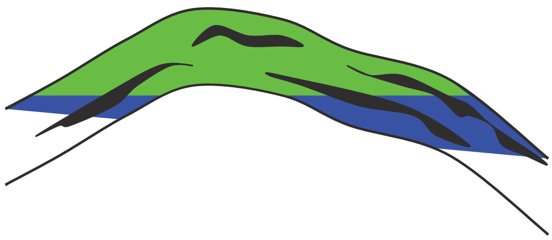
Deterministic method oil accumulation example

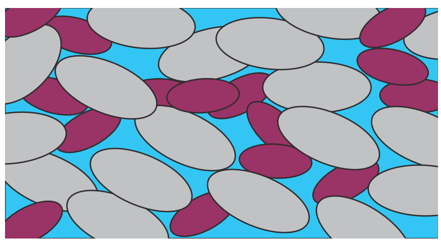
The principles are very simple….

HC in place Volume =
(Surface conditions)

HCIIP
OIIP
GIIP

Bulk rock volume	***GRV*** ***BRV***
*	
Net / Gross	***N /G***
*	
Porosity	***Phi***
*	
Oil saturation	***So= 1 - Sw***
*	
1/ Bo	***1/FVF***





1 mm

$$\boxed{OIIP = BRV * N/G * Phi * So * (1/Bo)}$$

*OIIP = BRV reservoir above OWC * average (N/G) * average Phi * average So * average (1/Bo)*

Why the probabilistic approach?

- The deterministic evaluation does not take into account the risk between different projects. The evaluation depends of the geoscientist team, that could be: pessimistic, neutral or optimistic.
- The probabilistic concept yields a range of values rather than a single value, and amongst them three values: P90, P50 and P10.
- The geostatistical methods were developed due to the capability of the computers to process huge amount of data (memory, speed, software etc.)

Specify input probability distributions
ϕ, N/G, BRV etc.

↓

Convert into cumulative probability distributions

↓

Specified input probability distributions
ϕ, N/G, BRV etc.

↓

Combine to calculate reserves from

$$RR = \frac{BRV * N/G * \phi * Shc * RF}{FVF}$$

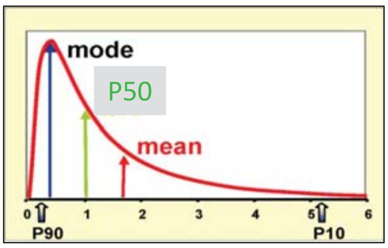
→ Repeat n times → Convert into cumulative probability distributions

↓

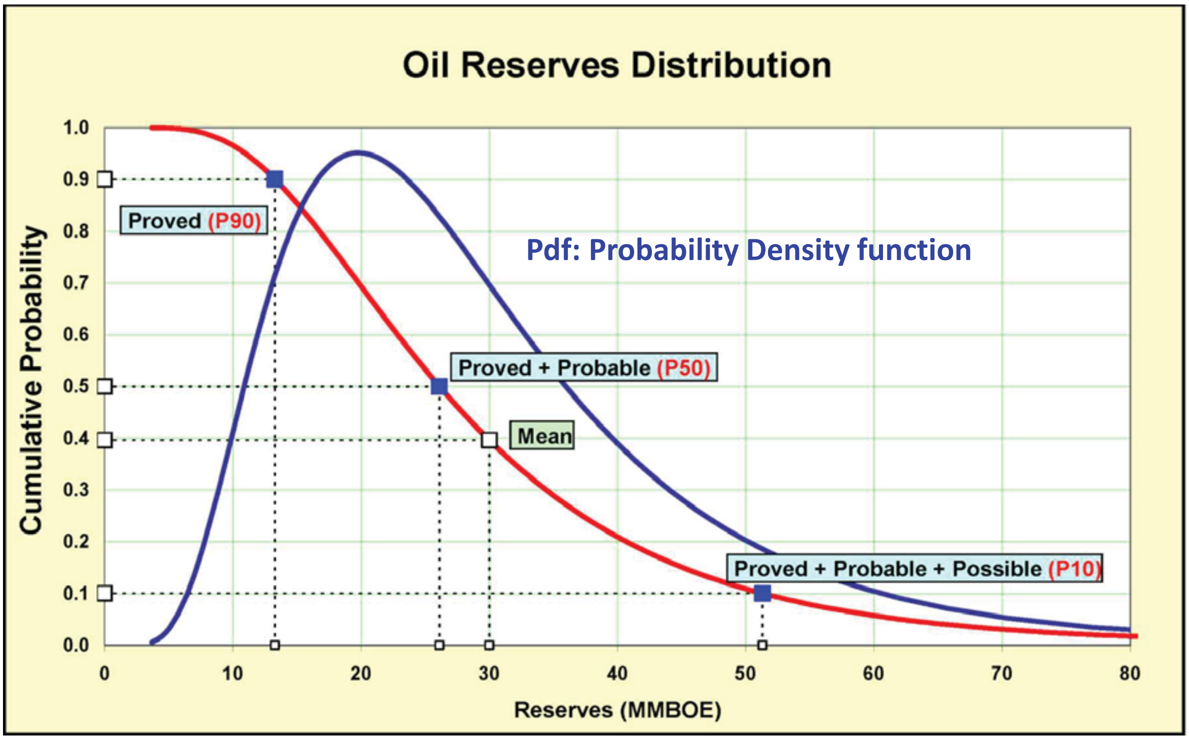
OUTPUT

→ Probability distribution of reserves

→ Cum. Prob. Distribution of reserves



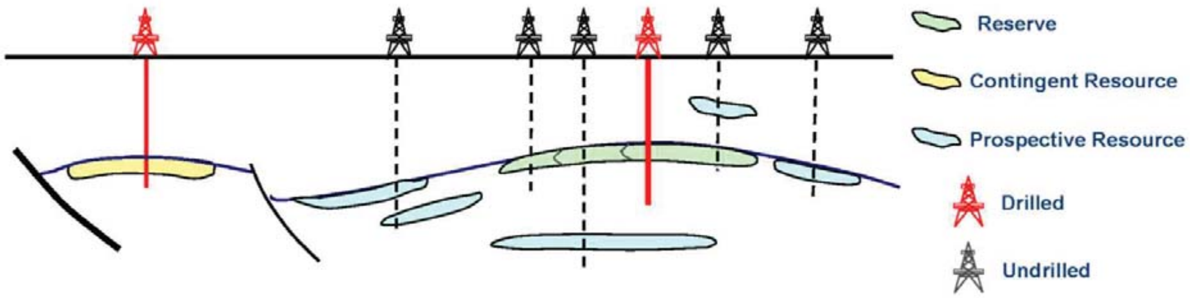
Reserves Distribution 2 (Descending CDF)



Proved Reserves (1P)

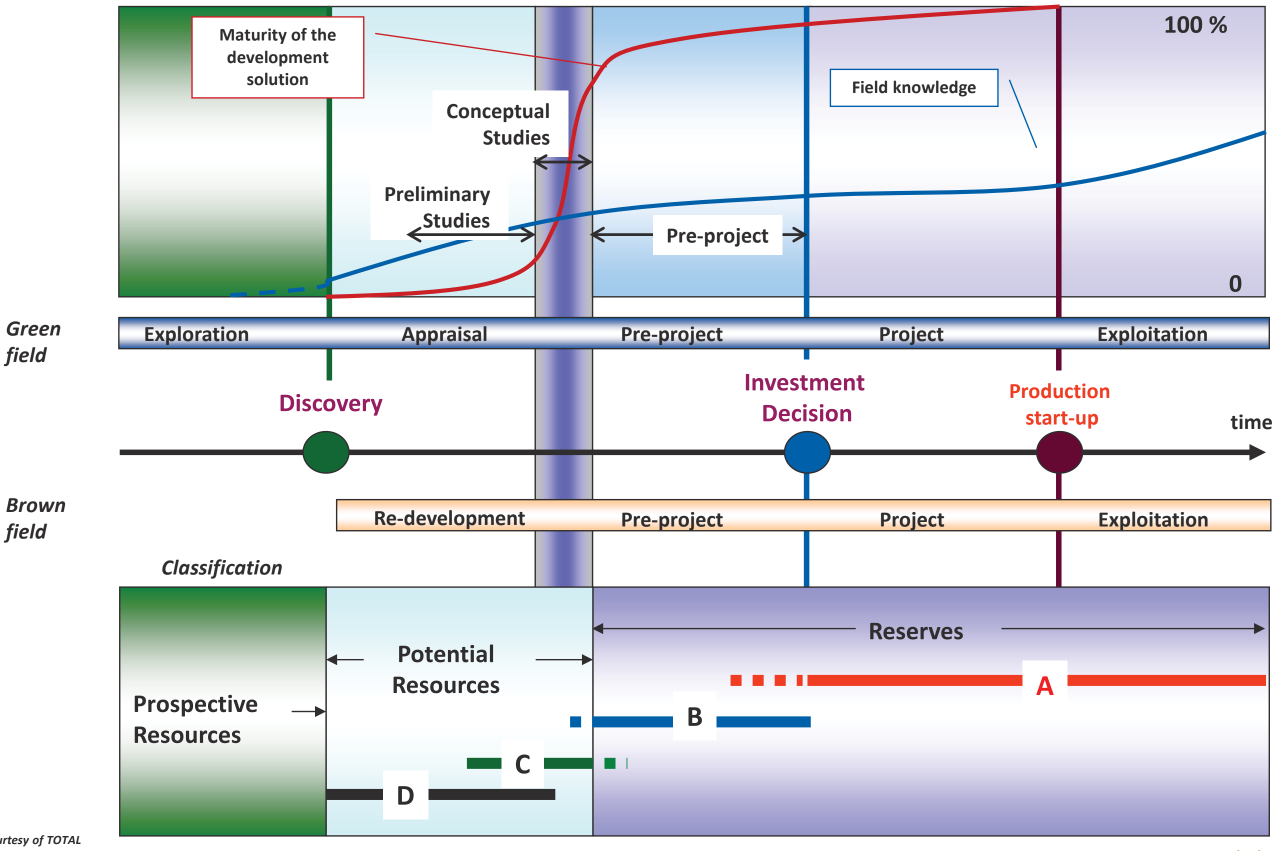
- Conditions to have PROVED Reserves:
- Known reservoir (faults blocks may be an issue)
- Known fluids and contacts (PVT data and seismic may help)
- Known productivity (production test or logs plus analog)
- Known drainage mechanism (enhanced recovery may require a pilot or a an analog - at least for SEC)
- Firm development plan
- Known contractual conditions (gas contract - FID within 3 years)

Reserves & Resources Classification



Uncertainty Range

Reserves	1P = P90	2P = P50	3P = P10	Development ensured
Contingent Resources	Low # P90	Best # P50	High # P10	Discovered, development not ensured
Prospective Resources	Min	Mode	Maxi	Prospects



Courtesy of TOTAL

Reserves classification system

- **Project refers to:**
  - a specific development on a reservoir or part of a reservoir
- **Category: describes the uncertainty on a volume estimate**
  - 1P (Proved or low estimate): P90
  - 2P (Proved plus Probable or best estimate): P50
  - 3P (Proved plus Probable plus Possible or high estimate): P10
- **Status: describes the technical & economical maturity of a project**
  - Status A: in production or in commitment for development
  - Status B: planned for development
  - Status C: development under evaluation
  - Status D: development not viable

International Frameworks

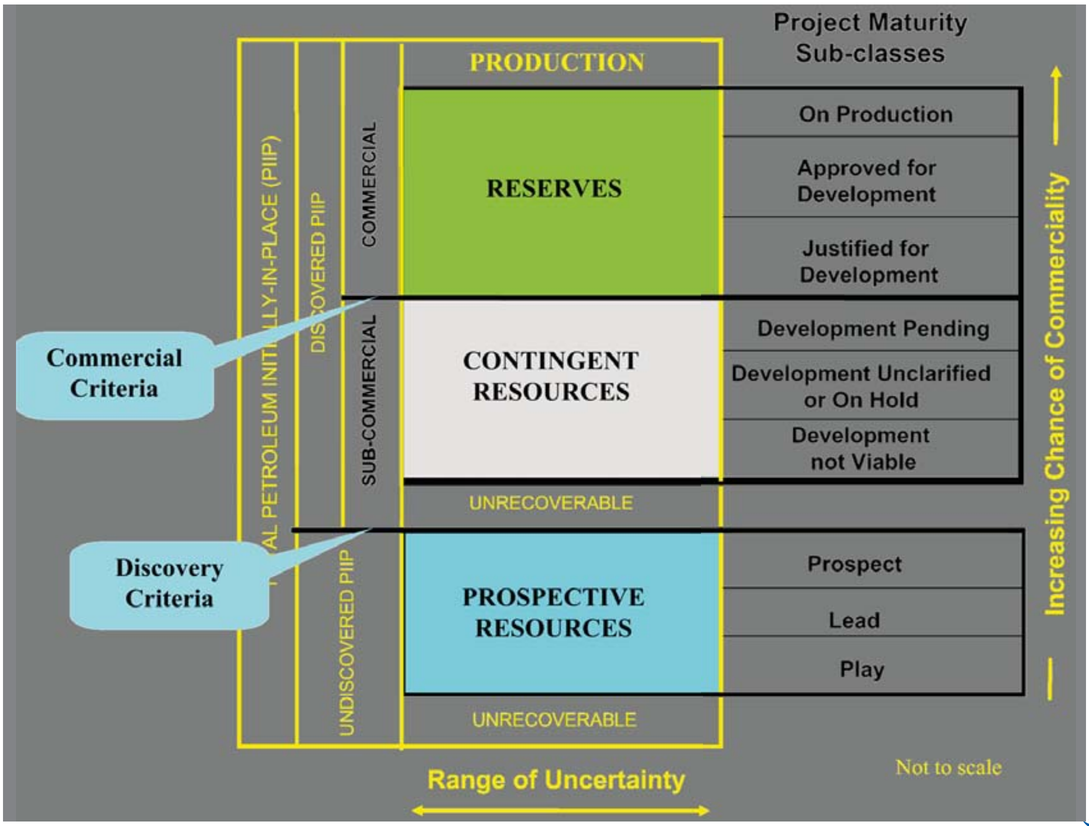
- **SPE Petroleum Resources Management System (PRMS)**
  - Project based & captures uncertainties
- **SEC: Security and Exchange Commission**
  - Protects investor's interest BUT does not capture complexity of today's technical environment
- **UNFC: United Nations Framework Classification**
  - Powerful for global assessment of energies BUT too complex & difficult to implement Audit Trail

PRMS - Major Principles

- The System is "Project-Based"
- Classification is based on project's chance of commerciality.
- Categorization is based on recoverable uncertainty
- Base case uses evaluator's forecast of future conditions
- Applies to both conventional and unconventional resources

PRMS - Major Principles

Sub-classify by Project Maturity



1P SEC Reserves

- **1P SEC reserves=**
  - estimated using geological and engineering data to determine with reasonable certainty whether the crude oil or natural gas in known reservoirs is recoverable under existing economic and operating conditions.
- **Standard calculation of reserves is requested by the SEC:**
  - Using oil market price closing at year end
  - Which means it needs an economic evaluation
- **Standard reporting form (20-F) to SEC by the Company**

SEC compliance

Proved Reserves (1P)

- **Testing**
  - Economic productivity supported by actual production or conclusive formation test
  - Gulf Of Mexico exemption: Log, core, MDT and seismic may suffice
- **HDT / HUT (LKH / HKO)**
  - Proved in well
  - Contact information must be established by well penetration
  - Use of RFT/MDT pressure gradient data to establish contacts may not be acceptable
- **Continuity of production**
  - 1P for undrilled units only if certainty of continuity of production
- **Commitment to develop**
  - SEC proved reserves must be economic
  - Signed sales contracts, for gas
  - request for proposals to build facilities,
  - firm plans and timetables...

Reserves and Resources : 1P / 2P /3P

- **Assuming field reserves follow a log-normal law:**
  - 1P = Proved reserves
  - 2P = Proved + probable reserves
  - 3P = Proved + probable + possible reserves = « resources »
- **1P reserves are mainly used in the SEC reporting. Companies tend to criticize the narrow definition used by SEC which gives a poor idea of their assets:**
  - Technical progress in reservoir knowledge is not taken into account
- **Internally, the Companies use 2P reserves:**
  - For their Long Term Plan
  - For project economics as the base case (generally 1P and 3P cases will also be run as respectively crash case and upside assessment)

3. Introduction to Risks and Uncertainties

Risk and Uncertainty

Two basic notions

- **Risk**
  - Risk is the probability that the parameter of interest fails to work at the minimum expected level
  - Example of application: exploration, “Fiches Prospect”, Decision Trees
  - E.g. Will this well find oil? ➔ probability

- **Uncertainty**
  - Uncertainty is the variation in the range of possible outcomes
  - Used for development decisions
  - E.g. How much oil will it produce? ➔range of values

Introduction: Risks versus Uncertainties

- **The risk stands for any geological reason that might rule out the geological hypothesis or model:**
  - Should a risk happen to come true, it would invalidate the prospect assessment.
  - To evaluate the risk on a prospect is to measure the prospect failure probability.
- **Given a geological hypothesis or model:**
  - the uncertainty measures the lack of capacity to ascertain the actual value of a parameter.
  - The uncertainty does not invalidate the hypothesis or the model.
- **Risk assessment can also be linked to projects such as:**
  - Value of Information by shooting 4D seismic to evaluate by-passed oil
  - Value of Information by shooting new seismic to improve the reservoir characterization, thus improving the development plan in (water or gas) injection projects.

Why Evaluate Risk and Uncertainty?

- To make better investment decisions
- Risk ➔ ranking of projects
- Uncertainty ➔ decisions not optimal ➔ financial loss
- The purpose of risk assessment in petroleum exploration is to estimate the probability of discovery prior to drilling of a mapped prospect.
  - Calculation of the economic value of prospects
  - Assessment of the undiscovered resources in a given area during play evaluation
  - Ranking of prospects

Reserves	Facilities	Loss
Over-estimated	too large	CAPEX, maintenance
Under-estimated	too small	Production, CAPEX for resizing

Geological Risk Assessment

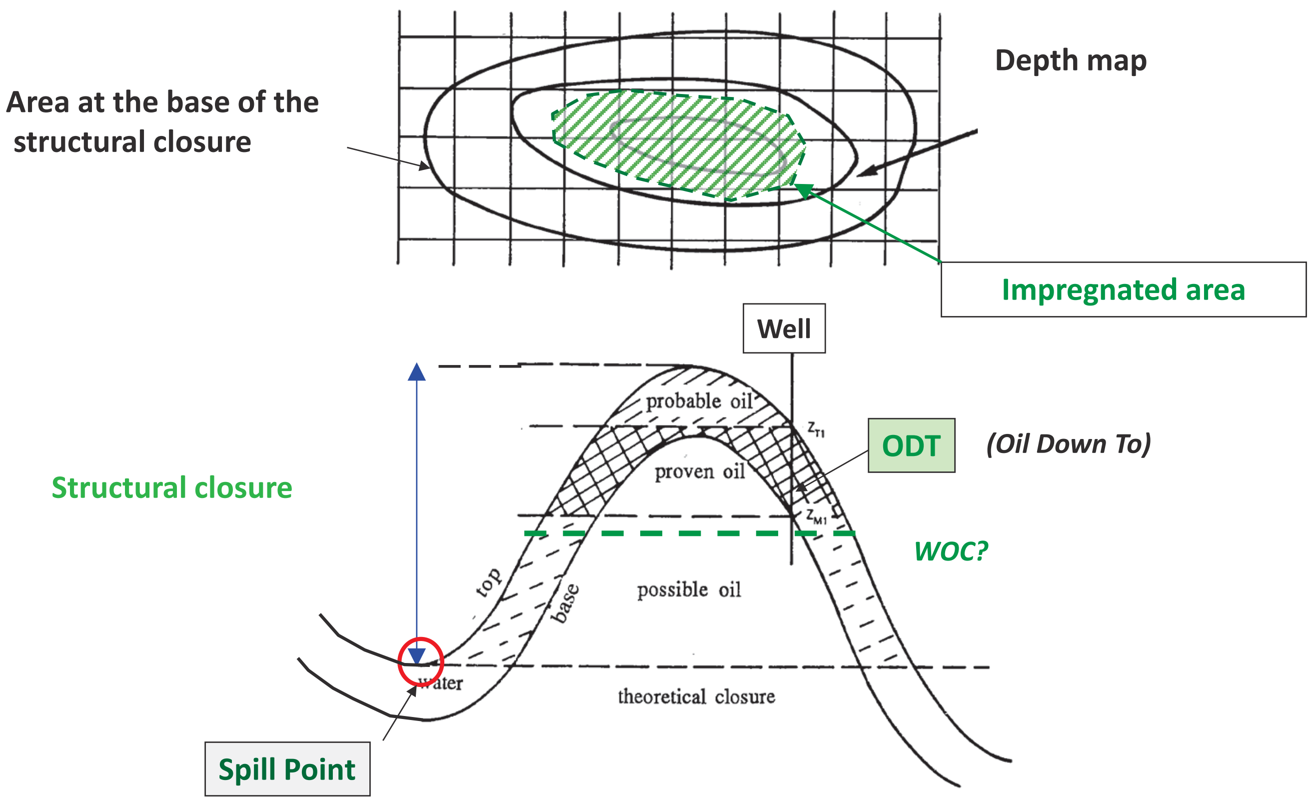
- The geological risk assessment requires an evaluation of those geological factors that are critical to the discovery of recoverable quantities of hydrocarbons
- The probability of discovery is a function of the major probability factors, each of which must be evaluated with respect to presence and effectiveness
- As they are considered independent, the POS is the multiplication of all the single risk values.
- Depending on companies, the POS can be the multiplication of 3 to 8 single risks.
- Probability Pj of:
  - Reservoir
  - Trap
  - Hydrocarbon charge
  - Timing of migration
  - Retention of hydrocarbons in the trap

$$POS = \prod_{j=1}^{n} P_j$$

Managing the uncertainties

- **Seismic**
  - Migration
  - Velocity law
  - Picking
  - Time-depth conversion
- **Geology**
  - Sedimentary concept, size of sedimentary bodies, distribution, shape
  - Facies
  - Phi, N/G, Sw…
  - Contacts
- **Dynamics**
  - Fault transmisivities
  - Extension of barriers
  - Kv/Kh
  - PVT
  - Kr

Examples of uncertainties: geometry and contacts



Key points

- **Accumulation: Volume of hydrocarbons in place (expressed in standard conditions)**
- **Reserves: Part of this volume recovered by technical and economical procedure. Usually classified in "Proved", "Probable" and "Possible" categories.**
- **Reserves classification:**
  - Proved: are those quantities of petroleum which, by analysis of geological and engineering data, can be estimated with reasonable certainty to be commercially recoverable, from a given date forward, from known reservoirs and under current economic conditions, operating methods and government regulations
  - Probable: are unproved reserves which, by analysis of geological and engineering data, are more likely than not to be recoverable.
  - Possible: are unproved reserves which, by analysis of geological and engineering data, are less likely to be recoverable than probable reserves

Key points

- **Risk is the probability that the parameter of interest fails to work at the minimum expected level**
- **Uncertainty is the variation in the range of possible outcomes**
- **The geological risk assessment requires an evaluation of those geological factors that are critical to the discovery of recoverable quantities of hydrocarbons**
- **The probability of discovery is a function of the major probability factors:**
  - Seismic: Migration, velocity law, picking, time-depth conversion
  - Geology: Sedimentary concept, size of sedimentary bodies, distribution, shape, facies, Phi, N/G, Sw, contacts
  - Dynamics: Fault transmisivities, extension of barriers, Kv/Kh, PVT, Kr

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